BUCKEYE PARTNERS, L.P.
Form 10-Q
August 06, 2010

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

(Mark One)

þ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the quarterly period ended June 30, 2010

OR

o **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 þ No o

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 þ No o

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

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

Limited partner units outstanding as of August 3, 2010: 51,535,672

TABLE OF CONTENTS

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. ***Financial Statements***

BUCKEYE PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per limited partner unit amounts)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Revenues:				
Product sales	$ 501,744	$ 201,777	$ 1,069,914	$ 470,556
Transportation and other services	165,532	149,443	328,536	297,504
Total revenue	667,276	351,220	1,398,450	768,060
Costs and expenses:				
Cost of product sales and natural gas storage services	498,645	193,440	1,068,382	444,116
Operating expenses	67,560	68,595	133,269	142,102
Depreciation and amortization	15,786	14,675	31,430	29,155
Asset impairment expense		72,540		72,540
General and administrative	11,446	8,365	20,510	16,439
Reorganization expense		28,113		28,113
Total costs and expenses	593,437	385,728	1,253,591	732,465
Operating income (loss)	73,839	(34,508)	144,859	35,595
Other income (expense):				
Earnings from equity investments	2,764	3,142	5,416	5,224
Interest and debt expense	(21,262)	(16,061)	(42,811)	(33,237)
Other income	84	156	239	267
Total other expense	(18,414)	(12,763)	(37,156)	(27,746)
Net income (loss)	55,425	(47,271)	107,703	7,849
Less: net income attributable to noncontrolling interests	(1,818)	(1,100)	(3,583)	(2,460)
Net income (loss) attributable to Buckeye Partners, L.P.	$ 53,607	$ (48,371)	$ 104,120	$ 5,389

Allocation of net income (loss) attributable to Buckeye Partners, L.P.:				
Net income allocated to general partner	$ 12,797	$ 11,455	$ 25,292	$ 23,121
Net income (loss) allocated to limited partners	$ 40,810	$ (59,826)	$ 78,828	$ (17,732)
Earnings (Loss) Per Limited Partner Unit:				
Basic	$ 0.79	$ (1.17)	$ 1.52	$ (0.36)
Diluted	$ 0.78	$ (1.17)	$ 1.51	$ (0.36)
Weighted average number of limited partner units outstanding:				
Basic	51,512	51,243	51,492	49,830
Diluted	51,712	51,243	51,673	49,830

See Notes to Unaudited Condensed Consolidated Financial Statements.

Table of Contents

BUCKEYE PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(In thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Net income (loss)	$ 55,425	$ (47,271)	$ 107,703	$ 7,849
Other comprehensive income (loss):				
Change in value of derivatives	(34,672)	353	(36,600)	543
Amortization of interest rate swaps	242	240	482	480
Amortization of benefit plan costs	(590)	1	(568)	(358)
Adjustment to funded status of benefit plans		7,970		7,970
Total other comprehensive income (loss)	(35,020)	8,564	(36,686)	8,635
Comprehensive income (loss)	$ 20,405	$ (38,707)	$ 71,017	$ 16,484

See Notes to Unaudited Condensed Consolidated Financial Statements.

Table of Contents

BUCKEYE PARTNERS, L.P.
CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except unit amounts)
(Unaudited)

	June 30, 2010	December 31, 2009
Assets:		
Current assets:		
Cash and cash equivalents	$ 12,513	$ 34,599
Trade receivables, net	113,576	124,165
Construction and pipeline relocation receivables	11,626	14,095
Inventories	275,174	310,214
Derivative assets	10,093	4,959
Assets held for sale		22,000
Prepaid and other current assets	67,621	103,691
Total current assets	490,603	613,723
Property, plant and equipment, net	2,227,659	2,228,265
Equity investments	98,568	96,851
Goodwill	208,876	208,876
Intangible assets, net	42,931	45,157
Other non-current assets	41,698	62,777
Total assets	$ 3,110,335	$ 3,255,649
Liabilities and partners capital:		
Current liabilities:		
Line of credit	$ 194,179	$ 239,800
Accounts payable	64,163	56,525
Derivative liabilities	367	14,665
Accrued and other current liabilities	116,903	106,743
Total current liabilities	375,612	417,733
Long-term debt	1,421,181	1,498,970
Other non-current liabilities	127,627	102,851
Total liabilities	1,924,420	2,019,554
Commitments and contingent liabilities		
Partners capital:		
Buckeye Partners, L.P. unitholders capital:		
	1,762	1,849

General Partner (243,914 units outstanding as of June 30, 2010 and December 31, 2009)		
Limited Partners (51,524,772 and 51,438,265 units outstanding as of June 30, 2010 and December 31, 2009, respectively)	1,199,649	1,214,136
Accumulated other comprehensive loss	(37,533)	(847)
Total Buckeye Partners, L.P. unitholders capital	1,163,878	1,215,138
Noncontrolling interests	22,037	20,957
Total partners capital	1,185,915	1,236,095
Total liabilities and partners capital	$ 3,110,335	$ 3,255,649

See Notes to Unaudited Condensed Consolidated Financial Statements.

Table of Contents

BUCKEYE PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Cash flows from operating activities:		
Net income	$ 107,703	$ 7,849
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	31,430	29,155
Asset impairment expense		72,540
Net changes in fair value of derivatives	(12,901)	4,672
Non-cash deferred lease expense	2,117	2,250
Reorganization expense		28,113
Earnings from equity investments	(5,416)	(5,224)
Distributions from equity investments	3,700	2,827
Amortization of other non-cash items	4,418	2,438
Change in assets and liabilities:		
Trade receivables	10,589	(2,832)
Construction and pipeline relocation receivables	2,469	4,855
Inventories	28,065	(27,742)
Prepaid and other current assets	36,679	(20,548)
Accounts payable	7,638	5,791
Accrued and other current liabilities	10,790	(3,912)
Other non-current assets	2,792	533
Other non-current liabilities	3,706	1,812
Total adjustments from operating activities	126,076	94,728
Net cash provided by operating activities	233,779	102,577
Cash flows from investing activities:		
Capital expenditures	(27,572)	(39,819)
Contributions to equity investments		(3,880)
Net proceeds from disposal of property, plant and equipment	22,274	21
Net cash used in investing activities	(5,298)	(43,678)
Cash flows from financing activities:		
Net proceeds from issuance of limited partner units		104,779
Proceeds from exercise of limited partner unit options	2,976	38
Borrowings under credit facility	95,000	77,333
Repayments under credit facility	(173,000)	(166,600)
Net (repayments) borrowings under BES credit agreement	(45,621)	3,000

Debt issuance costs	(3,227)	(18)
Costs associated with agreement and plan of merger	(1,341)	
Distributions paid to noncontrolling interests	(2,503)	(2,713)
Distributions paid to partners	(122,851)	(111,564)
Net cash used in financing activities	(250,567)	(95,745)
Net decrease in cash and cash equivalents	(22,086)	(36,846)
Cash and cash equivalents Beginning of period	34,599	58,843
Cash and cash equivalents End of period	$ 12,513	$ 21,997

See Notes to Unaudited Condensed Consolidated Financial Statements.

5

Table of Contents

BUCKEYE PARTNERS, L.P.
CONDENSED CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL (DEFICIT)
(In thousands)
(Unaudited)

	Buckeye Partners, L.P. Unitholders				
	General Partner	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Balance January 1, 2009	$ (6,680)	$ 1,201,144	$ (18,967)	$ 20,775	$ 1,196,272
Net income (loss)	23,121	(17,732)		2,460	7,849
Change in value of derivatives			543		543
Amortization of interest rate swaps			480		480
Adjustment to funded status of benefit plans			7,970		7,970
Amortization of benefit plan costs			(358)		(358)
Distributions paid to partners	(22,407)	(89,157)			(111,564)
Distributions paid to noncontrolling interests				(2,713)	(2,713)
Net proceeds from the issuance of limited partner units		104,779			104,779
Amortization of unit-based compensation awards		477			477
Exercise of limited partner unit options		38			38
Balance June 30, 2009	$ (5,966)	$ 1,199,549	$ (10,332)	$ 20,522	$ 1,203,773
Balance January 1, 2010	$ 1,849	$ 1,214,136	$ (847)	$ 20,957	$ 1,236,095
Net income	25,292	78,828		3,583	107,703
Costs associated with agreement and plan of merger		(1,846)			(1,846)
Change in value of derivatives			(36,600)		(36,600)
Amortization of interest rate swaps			482		482
Amortization of benefit plan costs			(568)		(568)
Distributions paid to partners	(25,379)	(97,472)			(122,851)
Distributions paid to noncontrolling interests				(2,503)	(2,503)
Non-cash accrual for distribution equivalent rights		(563)			(563)
Amortization of unit-based compensation awards		3,596			3,596
Exercise of limited partner unit options		2,976			2,976

Other		(6)			(6)
Balance June 30, 2010	$ 1,762	$ 1,199,649	$ (37,533)	$ 22,037	$ 1,185,915

See Notes to Unaudited Condensed Consolidated Financial Statements.

6

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Except for per unit amounts, or as otherwise noted within the context of each footnote disclosure, the dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands.

1. ORGANIZATION AND BASIS OF PRESENTATION

Partnership Organization

Buckeye Partners, L.P. is a publicly traded Delaware master limited partnership (MLP), the limited partner units (LP Units) of which are listed on the New York Stock Exchange (NYSE) under the ticker symbol BPL. 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 5,400 miles of pipeline and 67 active products terminals that provide aggregate storage capacity of approximately 27.2 million barrels. In addition, we operate and maintain approximately 2,400 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 major 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: Pipeline Operations; Terminalling & Storage; Natural Gas Storage; Energy Services; and Development & Logistics.

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 MLP that is also publicly traded on the NYSE under the ticker symbol BGH.

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 June 30, 2010, Services Company owned approximately 3.0% of our LP Units. Services Company employees provide services to our operating subsidiaries. Pursuant to a services agreement entered into in December 2004 (the Services Agreement), our operating subsidiaries reimburse Services Company for the costs of the services provided by Services Company.

Agreement and Plan of Merger

On June 10, 2010, we and our general partner entered into an Agreement and Plan of Merger (the Merger Agreement) with BGH, its general partner and Grand Ohio, LLC (Merger Sub), our subsidiary, pursuant to which Merger Sub will be 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 will be cancelled, the general partner units held by our general partner (representing an approximate 0.5% general partner interest in us) will be converted to a non-economic general partner interest, all of the economic interest in BGH will be acquired by us and BGH unitholders will receive aggregate consideration of approximately 20.0 million of our LP Units.

The terms of the Merger Agreement were unanimously approved by the audit committee of the board of directors of our general partner (Audit Committee), and by the board of directors of BGH s general partner. Additionally, the majority unitholder of BGH, BGH GP Holdings, LLC, and ArcLight Energy Partners Fund III, L.P., ArcLight Energy Partners Fund IV, L.P., Kelso Investment Associates VII, L.P., and KEP VI, LLC have executed a Support Agreement (Support Agreement) agreeing to vote in favor of the Merger and against any alternative transaction. The Support Agreement will automatically terminate if the board of directors of the general partner of BGH changes its recommendation to BGH s unitholders with respect to the Merger or the Merger Agreement is terminated.

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

After the Merger, the board of directors of our general partner is expected to consist of nine members, three of whom are expected to be the existing independent members of our Audit Committee, one of whom is expected to be the existing chief executive officer of our general partner and three of whom are expected to be the three existing independent members of the audit committee of the board of directors of BGH s general partner. In addition, BGH s general partner, which will own a non-economic general partner interest in BGH and will continue to be owned by BGH GP Holdings, LLC, will have the right and authority to designate two additional members of the board of directors, subject to reduction if BGH GP Holdings, LLC s ownership of our LP Units drops below certain thresholds. The remaining seven members of our general partner s board of directors will be elected by holders of our LP Units.

The Merger Agreement is subject to, among other things, approval by the affirmative vote of the holders of a majority of our LP Units outstanding and entitled to vote at a meeting of the holders of our LP Units, approval by the (a) affirmative vote of holders of a majority of BGH s common units and (b) affirmative vote of holders of a majority of BGH s common units and management units, voting together as a single class, and the effectiveness of a registration statement on Form S-4 with respect to the issuance of the LP Units in connection with the Merger.

The Merger will be accounted for as an equity transaction. Therefore, changes in BGH s ownership interest as a result of the Merger will not result in gain or loss recognition. BGH will be considered the surviving consolidated entity for accounting purposes, while we will be the surviving consolidated entity for legal and reporting purposes.

We incurred $1.8 million of costs associated with the Merger during the three and six months ended June 30, 2010, of which $1.3 million has been paid. We charged these costs directly to partners capital.

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements reflect all adjustments that are, in the opinion of our management, of a normal and recurring nature and necessary for a fair statement of our financial position as of June 30, 2010, and the results of our operations and cash flows for the periods presented. The results of operations for the three and six months ended June 30, 2010 are not necessarily indicative of results of our operations for the 2010 fiscal year. The unaudited condensed consolidated financial statements have been prepared pursuant to the rules and regulations of the U.S. Securities and Exchange Commission (SEC). We have eliminated all intercompany transactions in consolidation. Certain information and note disclosures normally included in annual financial statements prepared in accordance with U.S. generally accepted accounting principles (GAAP) have been condensed or omitted pursuant to those rules and regulations. These interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our Annual Report on Form 10-K for the year ended December 31, 2009, as filed with the SEC on February 26, 2010.

Reclassifications

Certain prior year amounts have been reclassified in the condensed consolidated statements of operations and condensed consolidated statements of cash flows to conform to the current-year presentation. The reclassification in the condensed consolidated statements of operations is as follows:

Earnings from equity investments are now presented on a separate line item in the condensed consolidated statements of operations for the three and six months ended June 30, 2009. The other investment income that had previously been included with earnings from equity investments has been reclassified and included in Other income in the 2009 period.

The reclassification in the condensed consolidated statements of cash flows is as follows:

We have separately disclosed cash flows from the issuance of long-term debt and borrowings under our credit facility for the six months ended June 30, 2009. These amounts had been included within the same line item in the 2009 period.

These reclassifications had no impact on net income (loss) or cash flows from operating, investing or financing activities.

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Recent Accounting Developments

Consolidation of Variable Interest Entities (VIEs). In June 2009, the Financial Accounting Standards Board (FASB) amended consolidation guidance for VIEs. The objective of this new guidance is to improve financial reporting by companies involved with VIEs. This guidance requires each reporting company to perform an analysis to determine whether the company s variable interest or interests give it a controlling financial interest in a VIE. The new guidance was effective for us on January 1, 2010. The adoption of this guidance did not have an impact on our consolidated financial statements.

Fair Value Measurements. In January 2010, the FASB issued guidance that requires new disclosures related to fair value measurements. The new guidance requires expanded disclosures related to transfers between Level 1 and 2 activities and a gross presentation for Level 3 activity. The new accounting guidance is effective for fiscal years and interim periods beginning after December 15, 2009, except for the new disclosures related to Level 3 activities, which are effective for fiscal years beginning after December 15, 2010 and for interim periods within those years. The new guidance became effective for us on January 1, 2010, except for the new disclosures related to Level 3 activities, which will be effective for us on January 1, 2011. We have included the enhanced disclosure requirements regarding fair value measurements in Note 13.

2. ACQUISITION AND DISPOSITION

Refined Petroleum Products Terminals and Pipeline Assets Acquisition

On November 18, 2009, we acquired from ConocoPhillips certain refined petroleum product terminals and pipeline assets for approximately $47.1 million in cash. In addition, we acquired certain inventory on hand upon completion of the transaction for additional consideration of $7.3 million. The assets include over 300 miles of active pipeline that provide connectivity between the East St. Louis, Illinois and East Chicago, Indiana markets and three terminals providing 2.3 million barrels of storage tankage. ConocoPhillips entered into certain commercial contracts with us concurrent with our acquisition regarding usage of the acquired facilities. We believe the acquisition of these assets has given us greater access to markets and refinery operations in the Midwest and increased the commercial value of these assets and certain of our existing assets to our customers by offering enhanced distribution connectivity and flexible storage capabilities. The operations of these acquired assets are reported in the Pipeline Operations and Terminalling & Storage segments. The purchase price has been allocated to the tangible and intangible assets acquired, as follows:

Inventory	$ 7,287
Property, plant and equipment	44,400
Intangible assets	4,580
Environmental and other liabilities	(1,834)
Allocated purchase price	$ 54,433

Sale of Buckeye NGL Pipeline

Effective January 1, 2010, we sold our ownership interest in an approximately 350-mile natural gas liquids pipeline (the Buckeye NGL Pipeline) that runs from Wattenberg, Colorado to Bushton, Kansas for $22.0 million. The assets had been classified as Assets held for sale in our consolidated balance sheet at December 31, 2009 with a carrying amount equal to the proceeds received. Revenues for Buckeye NGL Pipeline for the three and six months ended June 30, 2009 were $3.2 million and $6.5 million, respectively.

Table of Contents

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 April 2010, the Pipeline Hazardous Materials Safety Administration (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.

On July 30, 2010, a putative class action was filed by a unitholder against BGH, MainLine Management LLC (MainLine Management), BGH GP Holdings, LLC (BGH GP), and each of MainLine Management s directors in the District Court of Harris County, Texas under the caption *Broadbased Equities v. Forrest E. Wylie, et. al.* In the Petition, the plaintiff alleges that MainLine Management and its directors breached their fiduciary duties to BGH s public unitholders by, among other things, acting to facilitate the sale of BGH to Buckeye in order to facilitate the gradual sale by BGH GP of its interest in BGH and failing to disclose all material facts in order that the BGH unitholders can cast an informed vote on the Merger Agreement. Among other things, the Petition seeks an order certifying a class consisting of all BGH unitholders, a determination that the action is a proper derivative action, damages in an unspecified amount, and an award of attorneys fees and costs. The defendants have not yet answered or otherwise responded to the Petition.

On August 2, 2010, a putative class action was filed by a unitholder against BGH, MainLine Management, Grand Ohio, LLC, Buckeye, Buckeye GP, and each of MainLine Management s directors in the District Court of Harris County, Texas under the caption *Henry James Steward v. Forrest E. Wylie, et. al.* In the Petition, the plaintiff alleges that MainLine Management and its directors breached their fiduciary duties to BGH s public unitholders by, among other things, failing to disclose all material facts in order that the BGH unitholders can cast an informed vote on the Merger Agreement. The Petition also alleges that Buckeye, Buckeye GP and Grand Ohio, LLC aided and abetted the breaches of fiduciary duty. Among other things, the Petition seeks an order certifying a plaintiff class consisting of all of BGH unitholders, an order enjoining the Merger, rescission of the Merger, damages in an unspecified amount, and an award of attorneys fees and costs. Neither we nor the other defendants have yet answered or otherwise responded to the Petition.

On August 2, 2010, a putative class action was filed by a unitholder against BGH, MainLine Management, BGH GP, ArcLight Capital Partners, LLC (ArcLight), Kelso & Company (Kelso), Buckeye, Buckeye GP, and each of MainLine Management s directors, in the District Court of Harris County, Texas under the caption *Henry James Steward v. Forrest E. Wylie, et. al.* In the Petition, the plaintiff alleges that MainLine Management and its directors breached their fiduciary duties to BGH s public unitholders by, among other things, accepting insufficient consideration, failing to condition the Merger on a majority vote of public unitholders of BGH, and failing to disclose all material facts in order that the BGH unitholders can cast an informed vote on the Merger Agreement. The Petition also alleges that Buckeye, Buckeye GP, BGH GP, ArcLight, and Kelso aided and abetted the breaches of fiduciary duty. Among other things, the Petition seeks an order certifying a class consisting of all of BGH s unitholders, an order enjoining the Merger, damages in an unspecified amount, and an award of attorneys fees and costs. Neither we nor the other defendants have yet answered or otherwise responded to the Petition.

Environmental Contingencies

In accordance with our accounting policy, we recorded operating expenses, net of insurance recoveries, of $2.5 million and $1.2 million during the three months ended June 30, 2010 and 2009, respectively, and $5.4 million and $6.6 million during the six months ended June 30, 2010 and 2009, respectively, related to environmental expenditures unrelated to claims and proceedings.

Ammonia Contract Contingencies

On November 30, 2005, Buckeye Gulf Coast Pipe Lines, L.P. (BGC) 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, BGC assumed the obligations of EPME under several contracts involving monthly purchases and sales of ammonia. EPME and BGC agreed, however, that EPME would retain the economic risks and benefits associated with those contracts until their expiration at the end of 2012. To effectuate this agreement, BGC 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 costs exceeding ammonia sales proceeds. The amount of the shortfall generally increases as the market price of ammonia increases.

EPME has informed BGC that, notwithstanding the parties agreement, it will not continue to pay BGC for shortfalls created by the pass-through of ammonia costs in excess of ammonia revenues. EPME encouraged BGC to seek payment by invoking a $40.0 million guaranty made by El Paso, which guaranteed EPME s obligations to BGC. If EPME fails to reimburse BGC for these shortfalls for a significant period during the remainder of the term of the ammonia agreements, 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 BGC could adversely affect our financial position, results of operations and cash flows. To date, BGC has continued to receive payment for ammonia costs under the contracts at issue. BGC has not called on El Paso s guaranty and believes only BGC 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 have been working with EPME to terminate the ammonia sales contracts and ammonia supply contracts and, at no out of pocket cost to us, have terminated one of the ammonia sales contracts. Given, however, the uncertainty of future ammonia prices and EPME s future actions, we continue to believe we have risk of loss 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 and EPME are unable to terminate the remaining contracts or otherwise mitigate the remaining risk, including potential recourse against EPME and El Paso, with respect to this matter.

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Customer Bankruptcy

One of our customers filed for bankruptcy in October 2009; approximately $4.2 million remained payable to us from the customer pursuant to a pre-bankruptcy contract. In June 2010, we entered into a settlement with the bankrupt customer and its largest creditor pursuant to which we expect to be paid at least $2.0 million upon the sale of certain of the customer s assets within the bankruptcy proceedings, and we were released from both asserted and unasserted claims. At this time, we expect the sale of the assets to be completed, and the settlement payment to be made to us, in the third quarter of 2010. As a result of the settlement, our Development & Logistics segment recognized approximately $2.1 million in expense related to the write-off of a portion of the outstanding receivable balance during the three and six months ended June 30, 2010.

4. INVENTORIES

Our inventory amounts were as follows at the dates indicated:

	June 30, 2010	December 31, 2009
Refined petroleum products (1)	$ 264,638	$ 299,473
Materials and supplies	10,536	10,741
Total inventories	$ 275,174	$ 310,214

(1) Ending inventory was 130.4 million and 141.7 million gallons of refined petroleum products at June 30, 2010 and December 31, 2009, respectively.

At June 30, 2010 and December 31, 2009, approximately 95% and 99%, respectively, of our inventory was hedged. Hedged inventory is valued at current market prices with the change in value of the inventory reflected in our condensed consolidated statements of operations.

5. PREPAID AND OTHER CURRENT ASSETS

Prepaid and other current assets consist of the following at the dates indicated:

	June 30, 2010	December 31, 2009
Prepaid insurance	$ 2,226	$ 6,916

Insurance receivables	11,238	13,544
Ammonia receivable	1,690	7,429
Margin deposits	7,921	21,037
Prepaid services	21,742	21,571
Unbilled revenue	2,469	13,201
Tax receivable	7,162	7,162
Prepaid taxes	4,001	2,213
Other	9,172	10,618
Total prepaid and other current assets	$ 67,621	$ 103,691

11

Table of Contents

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

6. 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 Pipeline Operations segment, at the dates indicated:

	Ownership	June 30, 2010	December 31, 2009
Muskegon Pipeline LLC	40.0%	$ 14,514	$ 15,273
Transport4, LLC	25.0%	373	379
West Shore Pipe Line Company	24.9%	30,526	30,320
West Texas LPG Pipeline Limited Partnership	20.0%	53,155	50,879
Total equity investments		$ 98,568	$ 96,851

The following table presents earnings from equity investments for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Muskegon Pipeline LLC	$ 227	$ 173	$ 571	$ 538
Transport4, LLC	30	40	69	70
West Shore Pipe Line Company	1,294	1,094	2,501	2,197
West Texas LPG Pipeline Limited Partnership	1,213	1,835	2,275	2,419
Total earnings from equity investments	$ 2,764	$ 3,142	$ 5,416	$ 5,224

7. INTANGIBLE ASSETS

Intangible assets consist of the following at the dates indicated:

	June 30, 2010	December 31, 2009
Customer relationships	$ 38,300	$ 38,300
Accumulated amortization	(7,115)	(5,631)
Net carrying amount	31,185	32,669
Customer contracts	16,380	16,380
Accumulated amortization	(4,634)	(3,892)
Net carrying amount	11,746	12,488
Total intangible assets	$ 42,931	$ 45,157

For the three months ended June 30, 2010 and 2009, amortization expense related to intangible assets was $1.1 million and $0.9 million, respectively. For the six months ended June 30, 2010 and 2009, amortization expense related to intangible assets was $2.2 million and $1.8 million, respectively. Amortization expense related to intangible assets is expected to be approximately $4.5 million for each of the next five years.

Table of Contents

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

8. OTHER NON-CURRENT ASSETS

Other non-current assets consist of the following at the dates indicated:

	June 30, 2010	December 31, 2009
Deferred charge, net (1)	$ 3,675	$ 6,024
Prepaid services	8,065	11,640
Derivative assets		17,204
Debt issuance costs	12,459	11,058
Insurance receivables	7,530	7,265
Other	9,969	9,586
Total other non-current assets	$ 41,698	$ 62,777

(1) Net of accumulated amortization of $61.7 million and $58.2 million at June 30, 2010 and December 31, 2009, respectively. The market value of the LP Units issued in August 1997 in connection with the restructuring of Services Company s ESOP was $64.2 million. This fair value was recorded as a deferred charge and is being amortized on a straight-line basis over 13.5 years.

9. ACCRUED AND OTHER CURRENT LIABILITIES

Accrued and other current liabilities consist of the following at the dates indicated:

	June 30, 2010	December 31, 2009
Taxes - other than income	$ 16,201	$ 15,381
Accrued charges due Buckeye GP	694	1,218
Accrued charges due Services Company	2,829	6,104
Accrued employee benefit liability	3,287	3,287
Environmental liabilities	11,549	10,799
Accrued interest	30,695	30,609
Payable for ammonia purchase	1,803	7,015
Deferred revenue	20,306	6,829
Accrued capital expenditures	425	1,611
Reorganization		2,133
Deferred consideration	2,010	1,675
Other	27,104	20,082
Total accrued and other current liabilities	$ 116,903	$ 106,743

Table of Contents

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

10. DEBT OBLIGATIONS

Long-term debt consists of the following at the dates indicated:

	June 30, 2010	December 31, 2009
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
6.750% Notes due August 15, 2033 (1)	150,000	150,000
Credit Facility		78,000
BES Credit Agreement	194,179	239,800
Total debt	1,619,179	1,742,800
Less: Unamortized discount	(4,525)	(4,854)
Adjustment associated with fair value hedges	706	824
Subtotal debt	1,615,360	1,738,770
Less: Current portion of long-term debt	(194,179)	(239,800)
Total long-term debt	$ 1,421,181	$ 1,498,970

(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.

The fair values of our aggregate debt and credit facilities were estimated to be $1,672.6 million and $1,762.1 million at June 30, 2010 and December 31, 2009, 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.

Credit Facility

We have a borrowing capacity of $580.0 million under an unsecured revolving credit agreement (the Credit Facility) with SunTrust Bank, as administrative agent, which may be expanded up to $780.0 million subject to certain conditions and upon the further approval of the lenders. The Credit Facility s maturity date is August 24, 2012, which we may extend for up to two additional one-year periods. Borrowings under the Credit Facility bear interest under one of two rate options, selected by us, equal to either (i) the greater of (a) the federal funds rate plus 0.5% and (b) SunTrust Bank s prime rate plus an applicable margin, or (ii) the London Interbank Offered Rate (LIBOR) plus an applicable margin. The applicable margin is determined based on the current utilization level of the Credit Facility and ratings assigned by Standard & Poor s Rating Services and Moody s Investor Service for our senior unsecured non-credit enhanced long-term debt. At June 30, 2010, no amounts were outstanding under the Credit Facility, while at December 31, 2009, $78.0 million was outstanding under the Credit Facility.

The Credit Facility requires us to maintain a specified ratio (the Funded Debt Ratio) of no greater than 5.00 to 1.00 subject to a provision that allows 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, in each case excluding the income of certain of our majority-owned subsidiaries and equity investments (but including distributions from those majority-owned subsidiaries and equity investments). At June 30, 2010, our Funded Debt Ratio was approximately 3.86 to 1.00. As permitted by the Credit Facility, the $194.2 million of borrowings by Buckeye Energy Services LLC (BES) under its separate credit agreement (discussed below) was excluded from the calculation of the Funded Debt Ratio.

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

In addition, the Credit Facility contains other covenants including, but not limited to, covenants limiting our ability to incur additional indebtedness, to create or incur liens on our property, to dispose of property material to our operations, and to consolidate, merge or transfer assets. At June 30, 2010, we were not aware of any instances of noncompliance with the covenants under our Credit Facility.

At June 30, 2010 and December 31, 2009, we had committed $1.4 million in support of letters of credit. The obligations for letters of credit are not reflected as debt on our condensed consolidated balance sheets.

BES Credit Agreement

BES had a credit agreement (the BES Credit Agreement) that provided for borrowings of up to $250.0 million with a maturity date of May 20, 2011. On June 25, 2010, BES amended and restated the BES Credit Agreement to increase the total commitments for borrowings available to BES up to $500.0 million. However, the maximum amount available to be borrowed under the amended and restated BES Credit Agreement is initially limited to $350.0 million. An accordion feature provides BES the ability to increase the commitments under the BES Credit Agreement to $500.0 million, subject to obtaining the requisite commitments and satisfying other customary conditions. In addition to the accordion, subject to BES s satisfaction of certain financial covenants as set forth in the financial covenants table below, BES may, from time to time, elect to increase or decrease the maximum amount available for borrowing under the BES Credit Agreement in $5.0 million increments, but in no event below $150.0 million or above $500.0 million. The maturity date of the BES Credit Agreement is June 25, 2013. BES incurred $3.2 million of debt issuance costs related to the amendment, which will be amortized into interest expense over the term of the BES Credit Agreement.

Under the BES Credit Agreement, borrowings accrue interest under one of three rate options, at BES s election, equal to (i) the Administrative Agent s Cost of Funds (as defined in the BES Credit Agreement) plus 2.25%, (ii) the Eurodollar Rate (as defined in the BES Credit Agreement) plus 2.25% or (iii) the Prime Rate (as defined in the BES Credit Agreement) plus 1.25%. The BES Credit Agreement also permits Daylight Overdraft Loans (as defined in the BES Credit Agreement), Swingline Loans (as defined in the BES Credit Agreement) and letters of credit. Such alternative extensions of credit are subject to certain conditions as specified in the BES Credit Agreement. The BES Credit Agreement is secured by liens on certain assets of BES, including its inventory, cash deposits (other than certain accounts), investments and hedging accounts, receivables and intangibles.

The balances outstanding under the BES Credit Agreement were approximately $194.2 million and $239.8 million at June 30, 2010 and December 31, 2009, respectively, both of which were classified as current liabilities in our condensed consolidated balance sheets. The BES Credit Agreement requires BES to meet certain financial covenants, which are defined in the BES Credit Agreement and summarized below (in millions, except for the leverage ratio):

Borrowings outstanding on BES Credit Agreement	Minimum Consolidated Tangible Net Worth	Minimum Consolidated Net Working Capital	Maximum Consolidated Leverage Ratio
$150	$ 40	$ 30	7.0 to 1.0
Above $150 up to $200	$ 50	$ 40	7.0 to 1.0
Above $200 up to $250	$ 60	$ 50	7.0 to 1.0
Above $250 up to $300	$ 72	$ 60	7.0 to 1.0
Above $300 up to $350	$ 84	$ 70	7.0 to 1.0
Above $350 up to $400	$ 96	$ 80	7.0 to 1.0
Above $400 up to $450	$108	$ 90	7.0 to 1.0
Above $450 up to $500	$120	$100	7.0 to 1.0

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

At June 30, 2010, BES s Consolidated Tangible Net Worth and Consolidated Net Working Capital were $121.3 million and $71.5 million, respectively, and the Consolidated Leverage Ratio was 2.3 to 1.0. The weighted average interest rate for borrowings outstanding under the BES Credit Agreement was 2.5% at June 30, 2010.

In addition, the BES Credit Agreement contains other covenants, including, but not limited to, covenants limiting BES s ability to incur additional indebtedness, to create or incur certain liens on its property, to consolidate, merge or transfer its assets, to make dividends or distributions, to dispose of its property, to make investments, to modify its risk management policy, or to engage in business activities materially different from those presently conducted. At June 30, 2010, we were not aware of any instances of noncompliance with the covenants under the BES Credit Agreement.

11. OTHER NON-CURRENT LIABILITIES

Other non-current liabilities consist of the following at the dates indicated:

	June 30, 2010	December 31, 2009
Accrued employee benefit liabilities (see Note 14)	$ 45,799	$ 45,837
Accrued environmental liabilities	18,891	19,053
Deferred consideration	17,420	18,425
Derivative liabilities	18,953	
Deferred rent	11,275	9,158
Deferred revenue	7,082	1,532
Other	8,207	8,846
Total other non-current liabilities	$ 127,627	$ 102,851

12. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	June 30, 2010	December 31, 2009
Adjustments to funded status of retirement income guarantee plan and retiree medical plan	$ (4,453)	$ (4,453)
Amortization of interest rate swap	(7,271)	(7,753)
Derivative instruments	(19,099)	17,501
Accumulated amortization of retirement income guarantee plan and retiree medical plan	(6,710)	(6,142)
Total accumulated other comprehensive loss	$ (37,533)	$ (847)

13. 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 have no trading derivative instruments and do not engage in hedging activity with respect to trading instruments.

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Our policy is to 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 January 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 the 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 be possible on acceptable terms. During 2009, we entered into four forward-starting interest rate swaps with a total aggregate notional amount of $200.0 million related to the anticipated issuance of debt on or before July 15, 2013 and three forward-starting interest rate swaps with a total aggregate notional amount of $150.0 million related to the anticipated issuance of debt on or before October 15, 2014. During the three months ended June 30, 2010, we entered into two forward-starting interest rate swaps with a total aggregate notional amount of $100.0 million related to the anticipated issuance of debt on or before July 15, 2013 and three forward-starting interest rate swaps with a total aggregate notional amount of $125.0 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 and six months ended June 30, 2010, unrealized losses of $34.9 million and $36.2 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. 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.

Over the next twelve months, we expect to reclassify $1.0 million of accumulated other comprehensive loss as an increase to interest expense that was generated by forward-starting interest rate swaps terminated in 2008 associated with our 6.050% Notes.

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 fixed-price sales

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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. 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. Presentations 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 sales contracts. Therefore, our fixed-price sales contracts and the related futures contracts used to offset those fixed-price sales contracts are all marked-to-market on the 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 Pipeline Operations segment bought natural gas futures contracts in March 2009 with terms that coincide with the remaining term of an ongoing natural gas supply contract (through July 2011). We designated the futures contract as a cash flow hedge at inception.

The following table summarizes our commodity derivative instruments outstanding at June 30, 2010 (amounts in thousands of gallons, except as noted):

	Volume (1)		**Accounting**
Derivative Purpose	**Current**	**Long-Term** (2)	**Treatment**
Derivatives NOT designated as hedging instruments:			
Fixed-price sales contracts	29,050	168	Mark-to-market
Futures contracts for fixed-price sales contracts	24,612	168	Mark-to-market
Futures contracts for inventory	2,777		Mark-to-market
Derivatives designated as hedging instruments:			
Futures contracts for inventory	123,522		Fair Value Hedge
Futures contracts for natural gas (BBtu)	360	30	Cash Flow Hedge

(1) Volume represents net notional position.

(2) The maximum term for derivatives included in the long-term column is October 2011.

(3) BBtu represents one billion British thermal units.

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

	June 30, 2010			December 31, 2009		
	Assets Fair value	(Liabilities) Fair value	Derivative Net Carrying Value	Assets Fair value	(Liabilities) Fair value	Derivative Net Carrying Value
Derivatives NOT designated as hedging instruments:						
Fixed-price sales contracts	$ 5,213	$ (258)	$ 4,955	$ 4,959	$ (3,662)	$ 1,297
Futures contracts for fixed-price sales contracts	1,492	(1,806)	(314)	7,594	(384)	7,210
Futures contracts for inventory	3,336	(3,457)	(121)			
Derivatives designated as hedging instruments:						
Futures contracts for inventory	8,094	(2,748)	5,346	1,992	(20,517)	(18,525)
Futures contracts for natural gas		(140)	(140)	312		312
Interest rate contracts		(18,953)	(18,953)	17,204		17,204
Total			$ (9,227)			$ 7,498

Balance Sheet Locations:	June 30, 2010	December 31, 2009
Derivative assets	$ 10,093	$ 4,959
Other non-current assets		17,204
Derivative liabilities	(367)	(14,665)
Other non-current liabilities	(18,953)	
Total	$ (9,227)	$ 7,498

Our hedged inventory portfolio extends to the first quarter of 2011. The majority of the unrealized income of $5.2 million at June 30, 2010 for inventory hedges represented by futures contracts will be realized by the third quarter of 2010 as the related inventory is sold. Gains recorded on inventory hedges that were ineffective were approximately $1.0 million and $3.3 million for the three months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010 and 2009, gains recorded on inventory hedges that were ineffective were approximately $5.8 million and $7.6 million, respectively. At June 30, 2010, open refined petroleum product derivative contracts (represented by the fixed-price sales contracts and futures contracts for fixed-price sales contracts noted above) varied in duration, but did not extend beyond October 2011. In addition, at June 30, 2010, we had refined petroleum product inventories which we intend to use to satisfy a portion of the fixed-price sales contracts.

Table of Contents

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

		Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
	Location	2010	2009	2010	2009
Derivatives NOT designated as hedging instruments:					
Fixed-price sales contracts	Product sales	$ 6,268	$(13,866)	$ 8,678	$ (571)
Futures contracts for fixed-price sales contracts	Cost of product sales and natural gas storage services	(2,972)	19,007	(3,466)	11,461
Futures contracts for inventory	Cost of product sales and natural gas storage services	20		266	
Derivatives designated as fair value hedging instruments:					
Futures contracts for inventory	Cost of product sales and natural gas storage services	$18,123	$(31,251)	$13,213	$ (3,603)

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

		Gain (Loss) Reclassified from AOCI to Income			
		Three Months Ended June 30,		Six Months Ended June 30,	
	Location	2010	2009	2010	2009
Derivatives designated as cash flow hedging instruments:					
Futures contracts for natural gas	Cost of product sales and natural gas storage services	$ (96)	$ (162)	$ (168)	$ (215)
Futures contracts for refined petroleum products	Cost of product sales and natural gas storage services		(379)		(146)
Interest rate contracts	Interest and debt expense	(242)	(164)	(482)	(656)

Change in Value Recognized in OCI on Derivatives			
Three Months Ended June 30,		Six Months Ended June 30,	
2010	2009	2010	2009

<u>Derivatives designated as cash flow hedging instruments</u>:				
Futures contracts for natural gas	$ 85	$ 46	$ (611)	$ 163
Interest rate contracts	(34,853)	(158)	(36,157)	(157)

20

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 either 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.

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.

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Recurring

The following table sets forth financial assets and liabilities, measured at fair value on a recurring basis, as of the measurement dates, June 30, 2010 and December 31, 2009, and the basis for that measurement, by level within the fair value hierarchy:

	June 30, 2010		December 31, 2009	
	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:				
Fixed-price sales contracts	$	$ 5,121	$	$ 4,959
Futures contracts for inventory and fixed-price sales contracts	4,973			
Asset held in trust			1,793	
Interest rate derivatives				17,204
Financial liabilities:				
Fixed-price sales contracts		(166)		(3,662)
Futures contracts for inventory and fixed-price sales contracts	(202)		(11,003)	
Interest rate derivatives		(18,953)		
Total	$ 4,771	$ (13,998)	$ (9,210)	$ 18,501

The value of the Level 1 derivative assets and liabilities were based on quoted market prices obtained from the NYMEX. The value of the Level 1 asset held in trust was obtained from quoted market prices. The value of the Level 2 derivative assets and liabilities were based on observable market data related to the obligations to provide petroleum products. The value of the Level 2 interest rate derivatives was based on observable market data related to similar obligations.

The Level 2 derivative assets of $5.1 million and $5.0 million as of June 30, 2010 and December 31, 2009, respectively, are net of a credit valuation adjustment (CVA) of ($0.6) million and ($0.9) million, respectively. Because few of the Energy Services segment s customers entering into these fixed-price sales contracts are large organizations with nationally-recognized credit ratings, the Energy Services segment determined that a CVA, which is based on the credit risk of such contracts, is appropriate. The CVA is 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.

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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 impairment. The following table presents the fair value of an asset carried on the condensed consolidated balance sheet by asset classification and by level within the valuation hierarchy (as described above) at the date indicated for which a nonrecurring change in fair value has been recorded during the three and six months ended June 30, 2009:

	June 30, 2009	Level 1	Level 2	Level 3	Total Losses
Assets held for sale (1)	$ 5,760	$	$	$ 5,760	$ 72,540

(1) Represents net assets held for sale that were included in prepaid and other current assets at June 30, 2009 (see Note 2).

As a result of a loss in the customer base utilizing the Buckeye NGL Pipeline, we recorded a non-cash impairment charge of $72.5 million during the three and six months ended June 30, 2009. The estimated fair value was based on a probability-weighted combination of income and market approaches.

14. 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 June 30, 2010 and 2009:

	RIGP Three Months Ended June 30,		Retiree Medical Plan Three Months Ended June 30,	
	2010	2009	2010	2009
Service cost	$ 65	$ 207	$ 117	$ 105
Interest cost	227	369	786	491
Expected return on plan assets	(86)	(189)		
Amortization of prior service benefit	(11)	(118)	(1,175)	(859)
Amortization of unrecognized losses	242	355	354	261

Settlement/curtailment charge (1)		7,171		800
Net periodic benefit costs	$ 437	$ 7,795	$ 82	$ 798

(1) In connection with our reorganization in 2009, $8.0 million of the aggregate amount of $28.1 million of expenses incurred through June 30, 2009 was recorded as an adjustment to the funded status of the RIGP and the Retiree Medical Plan, which represent settlement and curtailment adjustments.

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The components of the net periodic benefit cost for the RIGP and Retiree Medical Plan were as follows for the six months ended June 30, 2010 and 2009:

	RIGP Six Months Ended June 30,		Retiree Medical Plan Six Months Ended June 30,	
	2010	2009	2010	2009
Service cost	$ 133	$ 415	$ 147	$ 210
Interest cost	459	740	991	983
Expected return on plan assets	(174)	(380)		
Amortization of prior service benefit	(23)	(235)	(1,482)	(1,719)
Amortization of unrecognized losses	490	712	447	522
Settlement/curtailment charge (1)		7,171		800
Net periodic benefit costs	$ 885	$ 8,423	$ 103	$ 796

(1) In connection with our reorganization in 2009, $8.0 million of the aggregate amount of $28.1 million of expenses incurred through June 30, 2009 was recorded as an adjustment to the funded status of the RIGP and the Retiree Medical Plan, which represent settlement and curtailment adjustments.

During the six months ended June 30, 2010, we contributed $1.5 million to the RIGP.

15. UNIT-BASED COMPENSATION PLANS

We award unit-based compensation to employees and directors primarily under the 2009 Long-Term Incentive Plan of Buckeye Partners, L.P. (the LTIP), which became effective in March 2009. 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 total unit-based compensation expense of $1.3 million and $0.4 million for the three months ended June 30, 2010 and 2009, respectively, and $2.5 million and $0.5 million for the six months ended June 30, 2010 and 2009, respectively.

Long-Term Incentive Plan

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 June 30, 2010, awards representing a total of 1,113,451 additional LP Units could be issued under the LTIP.

On December 16, 2009, the Compensation Committee approved the terms of the Buckeye Partners, L.P. Unit Deferral and Incentive Plan (Deferral Plan). The Compensation Committee is expressly authorized to adopt the Deferral Plan under the terms of the LTIP, which grants the Compensation Committee the authority to establish a program pursuant to which our phantom units may be awarded in lieu of cash compensation at the election of the employee. At December 31, 2009, eligible employees were allowed to defer up to 50% of their 2009 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 $1.8 million of 2009 compensation awards had been deferred at December 31, 2009, for which 62,332 phantom units (including matching units) were granted during the three months ended March 31, 2010. These grants are included as granted in the LTIP activity table below.

Table of Contents

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Awards under the LTIP

During the six months ended June 30, 2010, the Compensation Committee granted 123,290 phantom units to employees (including the 62,332 phantom units granted pursuant to the Deferral Plan discussed above), 12,000 phantom units to independent directors of Buckeye GP and MainLine Management, and 121,926 performance units to employees. The amount paid with respect to phantom unit distribution equivalents under the LTIP was $0.3 million for the six months ended June 30, 2010.

The following table sets forth the LTIP activity for the periods indicated:

	Number of LTP Units	Weighted Average Grant Date Fair Value per LP Unit (1)	Total Value
Unvested at January 1, 2010	140,095	$ 39.81	$ 5,577
Granted	257,216	56.20	14,455
Vested	(18,454)	39.17	(723)
Forfeited	(11,281)	48.28	(545)
Unvested at June 30, 2010	367,576	$ 51.05	$ 18,764

(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 June 30, 2010, approximately $13.1 million of compensation expense related to the LTIP is expected to be recognized over a weighted average period of approximately 2.2 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:

	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, 2010	349,400	$ 46.25		
Exercised	(68,200)	43.62		
Forfeited	(6,000)	49.47		
Outstanding at June 30, 2010	275,200	46.79	6.1	$ 3,371
Exercisable at June 30, 2010	176,000	$ 45.80	5.3	$ 2,331

(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 June 2010 and the exercise price, multiplied by the number of exercisable, in-the-money options.

Table of Contents

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The total intrinsic value of options exercised during the six months ended June 30, 2010 was $1.0 million. There were no option exercises during the six months ended June 30, 2009. At June 30, 2010, total unrecognized compensation cost related to unvested LP Unit options was $0.1 million. We expect to recognize this cost over a weighted average period of 0.7 years. At June 30, 2010, 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 $0.4 million and $0.3 million during the six months ended June 30, 2010 and 2009, respectively.

16. RELATED PARTY TRANSACTIONS

We are managed by Buckeye GP, which is a wholly owned subsidiary of BGH. BGH is managed by its general partner, MainLine Management. MainLine Management is a wholly owned subsidiary of BGH GP. Affiliates of each of ArcLight and Kelso, along with certain members of our senior management, own the majority of the outstanding equity interests of BGH GP. In addition to owning MainLine Management, BGH GP owns approximately 62% of BGH s common units.

Under certain agreements, we are obligated to reimburse Services Company for certain direct and indirect costs related to the business activities of us and our subsidiaries. Services Company is reimbursed for insurance-related expenses, general and administrative costs, compensation and benefits payable to employees of Services Company, tax information and reporting costs, legal and audit fees and an allocable portion of overhead expenses. BGH previously reimbursed Services Company for the executive compensation costs and related benefits paid to Buckeye GP s four highest salaried employees. Since January 1, 2009, we are paying for all executive compensation and related benefits earned by Buckeye GP s four highest salaried officers in exchange for an annual fixed payment from BGH of $3.6 million. Total costs incurred by us for the above services totaled $27.4 million and $52.7 million for the three months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010 and 2009, we incurred $54.9 million and $81.3 million, respectively, of such costs. Amounts for the 2009 periods include costs related to our organizational restructuring. We reimbursed Services Company for these costs.

Services Company, which is beneficially owned by the ESOP, owned 1.5 million of our LP Units (approximately 3.0% of our LP Units outstanding) as of June 30, 2010. Distributions received by Services Company from us on such LP Units are used to fund obligations of the ESOP. Distributions paid to Services Company totaled $1.4 million and $1.9 million for the three months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010 and 2009, distributions paid to Services Company totaled $3.0 million and $3.8 million, respectively. Total distributions paid to Services Company decrease over time as Services Company sells LP Units to fund benefits payable to ESOP participants who exit the ESOP.

We incurred a senior administrative charge for certain management services performed by affiliates of Buckeye GP of $0.5 million for the three months ended March 31, 2009. The senior administrative charge was waived indefinitely on April 1, 2009 as these affiliates are currently not providing services to us that were contemplated as being covered by the senior administrative charge. As a result, there were no related charges recorded in the last nine months of 2009 or during the six months ended June 30, 2010.

Buckeye GP receives incentive distributions from us pursuant to our partnership agreement and incentive compensation agreement. Incentive distributions are based on the level of quarterly cash distributions paid per LP Unit. Incentive distribution payments totaled $12.6 million and $11.5 million during the three months ended June 30, 2010 and 2009, respectively. During the six months ended June 30, 2010 and 2009, incentive distribution payments totaled $24.9 million and $22.0 million, respectively.

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

17. PARTNERS CAPITAL AND DISTRIBUTIONS

Summary of Changes in Outstanding General Partner Units and LP Units

The following is a reconciliation of General Partner Units and LP Units outstanding for the periods indicated:

	General Partner	Limited Partners	Total
Units outstanding at December 31, 2009	243,914	51,438,265	51,682,179
LP Units issued pursuant to the Option Plan		68,200	68,200
LP Units issued pursuant to the LTIP		18,307	18,307
Units outstanding at June 30, 2010	243,914	51,524,772	51,768,686

Cash 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 totaled $122.9 million and $111.6 million during the six months ended June 30, 2010 and 2009, respectively.

On August 6, 2010, we announced a quarterly distribution of $0.9625 per LP Unit that will be paid on August 31, 2010, to unitholders of record on August 16, 2010. Total cash distributed to unitholders on August 31, 2010 will total approximately $62.7 million.

18. EARNINGS PER LIMITED PARTNER UNIT

We use the two-class method for the computation of earnings per LP Unit. The two-class method requires the determination of net income allocated to limited partner interests as shown in the table below. Basic earnings per LP Unit is computed by dividing net income or loss allocated to limited partner interests per the two-class method by the weighted-average number of LP Units outstanding during a period. Diluted earnings per LP Unit is computed by dividing net income or loss allocated to limited partner interests per the two-class method by the weighted-average number of LP Units outstanding during a period, plus the dilutive effect of outstanding unit options and LTIP awards calculated using the treasury stock method. Outstanding unit options and LTIP awards are excluded from the calculation of diluted earnings per LP Unit in periods when we experience a net loss because the effect is antidilutive.

Table of Contents

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The amount of net income or loss allocated to limited partner interests is net of our general partner s share of such earnings. The following table presents the allocation of net income to our general partner for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Net income allocation:				
Net income (loss) attributable to Buckeye Partners, L.P.	$ 53,607	$ (48,371)	$ 104,120	$ 5,389
Less: General partner s allocation of incentive distributions	(12,604)	(11,739)	(24,919)	(23,205)
Net income available to limited partners and general partner after incentive distributions	41,003	(60,110)	79,201	(17,816)
General partner s ownership interest	0.471%	0.473%	0.471%	0.474%
Income (loss) allocation to general partner based upon ownership interest	$ 193	$ (284)	$ 373	$ (84)
General partner s incentive distributions	$ 12,604	$ 11,739	$ 24,919	$ 23,205
Income (loss) allocation to general partner	193	(284)	373	(84)
Total income allocated to general partner	12,797	11,455	25,292	23,121
Adjustment for application of two-class method for MLPs (1)	275		556	
Net income allocated to general partner in in accordance with two-class method	$ 13,072	$ 11,455	$ 25,848	$ 23,121

(1) We allocate net income to our general partner based on the distributions paid during the current quarter (including the incentive distribution interest in excess of the general partner s ownership interest). Guidance issued

by the FASB requires that the distribution pertaining to the current period net income, which is to be paid in the subsequent quarter, be utilized in the earnings per LP Unit calculation. We reflect the impact of this difference as the "Adjustment for application of two-class method for MLPs."

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following table presents the computation of basic and diluted earnings (loss) per LP Unit for the periods indicated:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Earnings per LP Unit Calculation:				
Numerator:				
Net income (loss) attributable to Buckeye Partners, L.P.	$ 53,607	$ (48,371)	$ 104,120	$ 5,389
Less: Net income allocated to general partner in accordance with two-class method	(13,072)	(11,455)	(25,848)	(23,121)
Net income (loss) available to limited partners in accordance with two-class method	$ 40,535	$ (59,826)	$ 78,272	$ (17,732)
Denominator: (in thousands)				
Basic:				
Weighted average LP Units outstanding	51,512	51,243	51,492	49,830
Diluted:				
Weighted average LP Units outstanding	51,512	51,243	51,492	49,830
Dilutive effect of LP Unit options and LTIP awards granted (1)	200		181	
Total	51,712	51,243	51,673	49,830
Earnings (loss) per LP Unit:				
Basic	$ 0.79	$ (1.17)	$ 1.52	$ (0.36)
Diluted	$ 0.78	$ (1.17)	$ 1.51	$ (0.36)

(1) For the three and six months ended June 30, 2009, the dilutive effect of unit-based compensation was not presented because its effect on the net

loss per LP Unit would have been antidilutive.

19. BUSINESS SEGMENTS

We operate and report in five business segments: Pipeline Operations; Terminalling & Storage; Natural Gas Storage; Energy Services; and Development & Logistics.

Adjusted EBITDA

In the first quarter of 2010, we revised our internal management reports provided to senior management, including the Chief Executive Officer, to redefine adjusted earnings before interest, taxes and depreciation and amortization (Adjusted EBITDA) to exclude non-cash unit-based compensation expense. We believe this revised measure provides an improved means by which to gauge our performance and increases comparability to similar measures used by other companies.

Adjusted EBITDA is the primary measure used by senior management to evaluate our operating results and to allocate our resources. We define Adjusted EBITDA 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, and (ii) non-cash unit-based compensation expense. In addition, we have excluded the Buckeye NGL Pipeline impairment expense of $72.5 million and the reorganization expense of $28.1 million from Adjusted EBITDA in order to

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

evaluate our results of operations on a comparative basis over multiple periods. EBITDA and Adjusted EBITDA are non-GAAP measures of performance and are reconciled to the most comparable GAAP measure, net income attributable to unitholders.

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.

Financial information about each segment, EBITDA and Adjusted EBITDA are presented below for the periods or at the dates indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Revenue:				
Pipeline Operations	$ 99,339	$ 98,175	$ 195,876	$ 197,370
Terminalling & Storage	40,768	29,429	83,139	60,072
Natural Gas Storage	21,249	16,672	46,655	31,749
Energy Services	501,949	201,676	1,070,151	470,156
Development & Logistics	10,785	8,805	18,300	17,930
Intersegment	(6,814)	(3,537)	(15,671)	(9,217)
Total revenue	$ 667,276	$ 351,220	$ 1,398,450	$ 768,060
Operating income (loss):				
Pipeline Operations	$ 45,393	$ (50,033)	$ 91,365	$ (5,117)
Terminalling & Storage	24,232	11,041	47,698	22,034
Natural Gas Storage	3,422	5,794	6,977	12,032
Energy Services	(158)	(1,480)	(3,234)	4,932
Development & Logistics	950	170	2,053	1,714
Total operating income (loss)	$ 73,839	$ (34,508)	$ 144,859	$ 35,595
Depreciation and amortization:				
Pipeline Operations	$ 9,770	$ 9,724	$ 19,411	$ 19,301
Terminalling & Storage	2,528	2,019	5,022	3,885
Natural Gas Storage	1,765	1,345	3,532	2,926
Energy Services	1,265	1,063	2,552	2,122
Development & Logistics	458	524	913	921
Total depreciation and amortization	$ 15,786	$ 14,675	$ 31,430	$ 29,155

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Adjusted EBITDA:				
Pipeline Operations	$ 57,614	$ 58,190	$ 115,431	$ 114,058
Terminalling & Storage	26,938	15,538	53,139	28,379
Natural Gas Storage	6,280	8,579	12,749	17,542
Energy Services	1,346	580	(195)	8,064
Development & Logistics	347	1,717	1,483	3,255
Total Adjusted EBITDA	$ 92,525	$ 84,604	$ 182,607	$ 171,298
GAAP Reconciliation:				
Net income (loss)	$ 55,425	$ (47,271)	$ 107,703	$ 7,849
Less: net income attributable to noncontrolling interests	(1,818)	(1,100)	(3,583)	(2,460)
Net income (loss) attributable to Buckeye Partners, L.P. unitholders	53,607	(48,371)	104,120	5,389
Interest and debt expense	21,262	16,061	42,811	33,237
Income tax (benefit) expense	(647)	63	(665)	128
Depreciation and amortization	15,786	14,675	31,430	29,155
EBITDA	90,008	(17,572)	177,696	67,909
Non-cash deferred lease expense	1,058	1,125	2,117	2,250
Non-cash unit-based compensation expense	1,459	398	2,794	486
Asset impairment expense		72,540		72,540
Reorganization expense		28,113		28,113
Adjusted EBITDA	$ 92,525	$ 84,604	$ 182,607	$ 171,298

	Six Months Ended June 30,	
	2010	2009
Capital additions, net: (1)		
Pipeline Operations	$ 14,252	$ 12,561
Terminalling & Storage	7,621	12,021
Natural Gas Storage	3,292	12,906
Energy Services	2,064	1,802
Development & Logistics	343	529
Total capital additions, net	$ 27,572	$ 39,819

Contributions to equity investments:		
Pipeline Operations	$	$ 3,880
Total contributions to equity investments	$	$ 3,880

(1) Amount excludes ($1.2) million and ($0.9) million of non-cash changes in accruals for capital expenditures for the six months ended June 30, 2010 and 2009, respectively (see Note 20).

31

Table of Contents

BUCKEYE PARTNERS, L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

	June 30, 2010	December 31, 2009
Total Assets:		
Pipeline Operations (1)	$ 1,536,124	$ 1,592,916
Terminalling & Storage	526,720	532,971
Natural Gas Storage	548,061	573,261
Energy Services	436,271	482,025
Development & Logistics	63,159	74,476
Total assets	$ 3,110,335	$ 3,255,649
Goodwill:		
Pipeline Operations	$	$
Terminalling & Storage	38,184	38,184
Natural Gas Storage	169,560	169,560
Energy Services	1,132	1,132
Development & Logistics		
Total goodwill	$ 208,876	$ 208,876

(1) All equity investments are included in the assets of the Pipeline Operations segment.

20. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flows and non-cash transactions were as follows for the periods indicated:

	Six Months Ended June 30, 2010	2009
Cash paid for interest (net of capitalized interest)	$ 40,022	$ 32,231
Cash paid for income taxes	417	1,292
Capitalized interest	1,117	2,684
Non-cash changes in assets and liabilities:		
Change in capital expenditures in accounts payable	$ (1,186)	$ (865)

21. SUBSEQUENT EVENT

On August 2, 2010, we completed the acquisition of additional shares of West Shore Pipe Line Company (West Shore) common stock from an affiliate of BP plc, resulting in an increase in our ownership interest in West Shore from 24.9% to 34.6%. We paid approximately $13.4 million for this additional interest.

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. The following information and such unaudited condensed consolidated financial statements should also be read in conjunction with 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 for the year ended December 31, 2009.

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 for the year ended December 31, 2009 and in this quarterly report on Form 10-Q. 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. You should not put undue reliance on any forward-looking statements. The forward-looking statements in this Quarterly Report 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 have adopted and followed in the preparation of our condensed consolidated financial statements is included in our Annual Report on Form 10-K for the year ended December 31, 2009. 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.

Overview of Business

Buckeye Partners, L.P. is a publicly traded Delaware master limited partnership (MLP), the limited partner units (LP Units) of which are listed on the New York Stock Exchange (NYSE) under the ticker symbol BPL. Unless the context requires otherwise, references to *we*, *us*, "*our* and *Buckeye* mean Buckeye Partners, L.P. and, where the context requires, include our subsidiaries.

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 MLP that is also publicly traded on the NYSE under the ticker symbol BGH.

Our primary business strategies are to generate stable cash flows, increase pipeline and terminal throughput and pursue strategic cash-flow accretive acquisitions that complement our existing asset base, improve operating efficiencies and allow increased cash distributions to our unitholders.

We operate and report in five business segments: Pipeline Operations; Terminalling & Storage; Natural Gas Storage; Energy Services; and Development & Logistics. We own and operate one of the largest independent refined petroleum products pipeline systems in the United States in terms of volumes delivered with approximately 5,400 miles of pipeline and 67 active products terminals that provide aggregate storage capacity of approximately 27.2 million barrels. In addition, we operate and maintain approximately 2,400 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 major 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.

Recent Developments

Agreement and Plan of Merger

On June 10, 2010, we and our general partner entered into an Agreement and Plan of Merger (the Merger Agreement) with BGH, its general partner, and Grand Ohio, LLC (Merger Sub), our subsidiary, pursuant to which Merger Sub will be 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 will be cancelled, the general partner units held by our general partner (representing an approximate 0.5% general partner interest in us) will be converted to a non-economic general partner interest, all of the economic interest in BGH will be acquired by us and BGH unitholders will receive aggregate consideration of approximately 20.0 million of our LP Units.

The terms of the Merger Agreement were unanimously approved by the audit committee of the board of directors of our general partner (Audit Committee), and by the board of directors of BGH s general partner. Additionally, the majority unitholder of BGH, BGH GP Holdings, LLC, and ArcLight Energy Partners Fund III, L.P., ArcLight Energy Partners Fund IV, L.P., Kelso Investment Associates VII, L.P., and KEP VI, LLC have executed a Support Agreement (Support Agreement) agreeing to vote in favor of the Merger and against any alternative transaction. The Support Agreement will automatically terminate if the board of directors of the general partner of BGH changes its recommendation to BGH s unitholders with respect to the Merger or the Merger Agreement is terminated.

After the Merger, the board of directors of our general partner is expected to consist of nine members, three of whom are expected to be the existing independent members of our Audit Committee, one of whom is expected to be the existing chief executive officer of our general partner and three of whom are expected to be the three existing independent members of the audit committee of the board of directors of BGH s general partner. In addition, BGH s general partner, which will own a non-economic general partner interest in BGH and will continue to be owned by BGH GP Holdings, LLC, will have the right and authority to designate two additional members of the board of directors, subject to reduction if BGH GP Holdings, LLC s ownership of our LP Units drops below certain thresholds. The remaining seven members of our general partner s board of directors will be elected by holders of our LP Units.

The Merger Agreement is subject to, among other things, approval by the affirmative vote of the holders of a majority of our LP Units outstanding and entitled to vote at a meeting of the holders of our LP Units, approval by the (a) affirmative vote of holders of a majority of BGH s common units and (b) affirmative vote of holders of a majority of BGH s common units and management units, voting together as a single class, and the effectiveness of a registration statement on Form S-4 with respect to the issuance of the LP Units in connection with the Merger.

The Merger will be accounted for as an equity transaction. Therefore, changes in BGH s ownership interest as a result of the Merger will not result in gain or loss recognition. BGH will be considered the surviving consolidated entity for accounting purposes, while we will be the surviving consolidated entity for legal and reporting purposes.

We incurred $1.8 million of costs associated with the Merger during the three and six months ended June 30, 2010, of which $1.3 million has been paid. We charged these costs directly to partners capital.

Amendment to BES Credit Agreement

On June 25, 2010, Buckeye Energy Services LLC (BES) amended and restated its credit agreement (the BES Credit Agreement) to increase the total commitments for borrowings available to BES up to $500.0 million. However, the maximum amount available to be borrowed under the amended and restated BES Credit Agreement is initially limited to $350.0 million. An accordion feature provides BES the ability to increase the commitments under the BES Credit Agreement to $500.0 million, subject to obtaining the requisite commitments and satisfying other customary conditions. In addition to the accordion, subject to BES s satisfaction of certain financial covenants, BES may, from time to time, elect to increase or decrease the maximum amount available for borrowing under the BES Credit Agreement in $5.0 million increments, but in no event below $150.0 million or above $500.0 million. The maturity date of the BES Credit Agreement is June 25, 2013. BES incurred $3.2 million of debt issuance costs related to the amendment, which will be amortized into interest expense over the term of the BES Credit Agreement. See Note 10 in the Notes to Unaudited Condensed Consolidated Financial Statements for further discussion.

Purchase of Additional Interest in West Shore Pipe Line Company

On August 2, 2010, we completed the acquisition of additional shares of West Shore Pipe Line Company (West Shore) common stock from an affiliate of BP plc, resulting in an increase in our ownership interest in West Shore from 24.9% to 34.6%. We paid approximately $13.4 million for this additional interest.

Sale of Buckeye NGL Pipeline

Effective January 1, 2010, we sold our ownership interest in an approximately 350-mile natural gas liquids pipeline (the Buckeye NGL Pipeline) that runs from Wattenberg, Colorado to Bushton, Kansas for $22.0 million. The assets had been classified as Assets held for sale in our consolidated balance sheet at December 31, 2009 with a carrying amount equal to the proceeds received.

Results of Operations

Adjusted EBITDA

In the first quarter of 2010, we revised our internal management reports provided to senior management, including the Chief Executive Officer, to redefine adjusted earnings before interest, taxes and depreciation and amortization (Adjusted EBITDA) to exclude non-cash unit-based compensation expense. We believe this revised measure provides an improved means by which to gauge our performance and increases comparability to similar measures used by other companies.

Adjusted EBITDA is the primary measure used by senior management to evaluate our operating results and to allocate our resources. We define EBITDA, a measure not defined under GAAP, as net income attributable to our unitholders before interest 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 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 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, and (ii) non-cash unit-based compensation expense. In addition, we have excluded the Buckeye NGL Pipeline impairment expense of $72.5 million and the reorganization expense of $28.1 million from Adjusted EBITDA in order to evaluate our results of operations on a comparative basis over multiple periods.

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 attributable to our unitholders, and these items may vary among other companies. Our senior management uses Adjusted EBITDA to

Table of Contents

evaluate consolidated operating performance and the operating performance of the 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.

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 attributable to our unitholders, which is the most comparable GAAP financial measure (in thousands).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Adjusted EBITDA:				
Pipeline Operations	$ 57,614	$ 58,190	$ 115,431	$ 114,058
Terminalling & Storage	26,938	15,538	53,139	28,379
Natural Gas Storage	6,280	8,579	12,749	17,542
Energy Services	1,346	580	(195)	8,064
Development & Logistics	347	1,717	1,483	3,255
Total Adjusted EBITDA	$ 92,525	$ 84,604	$ 182,607	$ 171,298
GAAP Reconciliation:				
Net income (loss)	$ 55,425	$ (47,271)	$ 107,703	$ 7,849
Less: net income attributable to noncontrolling interests	(1,818)	(1,100)	(3,583)	(2,460)
Net income (loss) attributable to Buckeye Partners, L.P. unitholders	53,607	(48,371)	104,120	5,389
Interest and debt expense	21,262	16,061	42,811	33,237
Income tax (benefit) expense	(647)	63	(665)	128
Depreciation and amortization	15,786	14,675	31,430	29,155
EBITDA	90,008	(17,572)	177,696	67,909
Non-cash deferred lease expense	1,058	1,125	2,117	2,250
Non-cash unit-based compensation expense	1,459	398	2,794	486
Asset impairment expense		72,540		72,540
Reorganization expense		28,113		28,113
Adjusted EBITDA	$ 92,525	$ 84,604	$ 182,607	$ 171,298

Segment Results

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Revenues:				
Pipeline Operations	$ 99,339	$ 98,175	$ 195,876	$ 197,370
Terminalling & Storage	40,768	29,429	83,139	60,072
Natural Gas Storage	21,249	16,672	46,655	31,749
Energy Services	501,949	201,676	1,070,151	470,156
Development & Logistics	10,785	8,805	18,300	17,930
Intersegment	(6,814)	(3,537)	(15,671)	(9,217)
Total revenues	$ 667,276	$ 351,220	$ 1,398,450	$ 768,060
Total costs and expenses: (1)				
Pipeline Operations	$ 53,946	$ 148,208	$ 104,511	$ 202,487
Terminalling & Storage	16,536	18,388	35,441	38,038
Natural Gas Storage	17,827	10,878	39,678	19,717
Energy Services	502,107	203,156	1,073,385	465,224
Development & Logistics	9,835	8,635	16,247	16,216
Intersegment	(6,814)	(3,537)	(15,671)	(9,217)
Total costs and expenses	$ 593,437	$ 385,728	$ 1,253,591	$ 732,465
Depreciation and amortization:				
Pipeline Operations	$ 9,770	$ 9,724	$ 19,411	$ 19,301
Terminalling & Storage	2,528	2,019	5,022	3,885
Natural Gas Storage	1,765	1,345	3,532	2,926
Energy Services	1,265	1,063	2,552	2,122
Development & Logistics	458	524	913	921
Total depreciation and amortization	$ 15,786	$ 14,675	$ 31,430	$ 29,155
Asset impairment expense:				
Pipeline Operations	$	$ 72,540	$	$ 72,540
Reorganization expense:				
Pipeline Operations	$	$ 23,054	$	$ 23,054
Terminalling and Storage		2,402		2,402
Natural Gas Storage		291		291
Energy Services		944		944
Development & Logistics		1,422		1,422

Total reorganization expense	$	$ 28,113	$	$ 28,113
Operating income (loss):				
Pipeline Operations	$ 45,393	$ (50,033)	$ 91,365	$ (5,117)
Terminalling & Storage	24,232	11,041	47,698	22,034
Natural Gas Storage	3,422	5,794	6,977	12,032
Energy Services	(158)	(1,480)	(3,234)	4,932
Development & Logistics	950	170	2,053	1,714
Total operating income (loss)	$ 73,839	$ (34,508)	$ 144,859	$ 35,595

(1) Total costs and expenses includes depreciation and amortization, asset impairment expense and reorganization expense.

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
Pipeline Operations (average bpd):				
Gasoline	668,900	685,700	639,100	659,200
Jet fuel	339,300	345,100	330,900	339,200
Diesel fuel	223,100	193,200	225,300	207,500
Heating oil	36,100	52,200	74,800	91,500
LPGs	21,300	18,800	20,900	16,600
NGLs		20,500		20,900
Other products	3,700	10,000	2,100	11,700
Total Pipeline Operations	1,292,400	1,325,500	1,293,100	1,346,600
Terminalling & Storage (average bpd):				
Products throughput (1)	570,000	459,800	563,200	470,200
Energy Services (in thousands of gallons):				
Sales volumes	235,100	134,000	502,100	317,000

(1) Reported quantities exclude transfer volumes, which are non-revenue generating transfers among our various terminals. For the three and six months ended June 30, 2009, we previously reported 489.4 thousand and 505.1 thousand, respectively, which included transfer volumes.

Three Months Ended June 30, 2010 Compared to Three Months Ended June 30, 2009

Consolidated

Adjusted EBITDA. Adjusted EBITDA increased by $7.9 million, or 9.4%, to $92.5 million for the three months ended June 30, 2010 from $84.6 million for the corresponding period in 2009. The Terminalling & Storage segment was primarily responsible for this increase in Adjusted EBITDA. The Terminalling & Storage segment s Adjusted EBITDA increased by $11.4 million for the three months ended June 30, 2010 as compared to the corresponding period in 2009, driven by increased throughput volumes, growth in fees, increased storage and rental revenues, the contribution from terminals acquired in November 2009 (see Note 2 in the Notes to Unaudited Condensed Consolidated Financial Statements), favorable settlement experience and lower operating expenses. The Energy Services segment s Adjusted EBITDA increased by $0.7 million for the three months ended June 30, 2010 as compared to the corresponding period in 2009 as a result of increased volumes of product sold, partially offset by increased costs and expenses.

These increases in Adjusted EBITDA were partially offset by decreases in Adjusted EBITDA in the Pipeline Operations segment, the Development & Logistics segment and the Natural Gas Storage segment. The Pipeline Operations segment s Adjusted EBITDA decreased by $0.6 million for the three months ended June 30, 2010 as compared to the corresponding period in 2009, due to decreased transportation revenues resulting from lower volumes transported during the three months ended June 30, 2010 and increased operating expenses, partially offset by the benefit of increased tariffs, favorable settlement experience and increased other revenues. The Development & Logistics segment s Adjusted EBITDA decreased by $1.3 million for the three months ended June 30, 2010 as compared to the corresponding period in 2009, due to $2.4 million of expenses related to the write-off in the 2010 period of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy (see Note 3 in the Notes to Unaudited Condensed Consolidated Financial Statements for further discussion) and reduced operating contract services, partially offset by revenues from the sale of ammonia linefill. The Natural Gas Storage segment s Adjusted EBITDA decreased by $2.3 million for the three months ended June 30, 2010 as compared to the corresponding period in 2009. High storage inventory levels in the western region, above normal temperatures and general uncertainty regarding the economic recovery have added pressure on market-based fees charged for storage services, and therefore led to a decrease in the net contribution from hub services activities and decreased lease revenue.

Overall, Adjusted EBITDA was also impacted favorably by the continued effectiveness of cost control measures we implemented in 2009. Largely as a result of these efforts, costs decreased by approximately $4.8 million during the three months ended June 30, 2010 as compared to the corresponding period in 2009. Offsetting this favorable impact was a decrease of $0.3 million in income from equity investments for the three months ended June 30, 2010 as compared to the corresponding period in 2009. The revenue and expense factors affecting the variance in consolidated Adjusted EBITDA are more fully discussed below.

Revenue. Revenue was $667.3 million for the three months ended June 30, 2010, which is an increase of $316.1 million, or 90.0%, from the three months ended June 30, 2009. This overall increase was caused by increases in revenues in all segments for the three months ended June 30, 2010 as compared to the corresponding period in 2009 as follows:

- an increase of $300.2 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 June 30, 2010 as compared to the corresponding period in 2009;
- an increase of $11.4 million in revenue from the Terminalling & Storage segment, resulting from increased throughput volumes, increased fees, storage and rental revenue, including $1.5 million in storage fees from previously underutilized tankage identified in connection with our best practices initiative and other marketing opportunities, increased revenue from the contribution of terminals acquired in November 2009 and favorable settlement experience;
- an increase of $4.5 million in revenue from the Natural Gas Storage segment, resulting primarily from higher fees from hub services transactions recognized as revenue, partially offset by reduced lease revenues as a result of general market conditions as discussed above;
- an increase of $2.0 million in revenue from the Development & Logistics segment, resulting primarily from the sale of ammonia linefill; and
- an increase of $1.1 million in revenue from the Pipeline Operations segment, resulting from the benefit of higher tariffs, favorable settlement experience, increased revenues from the contribution of pipeline assets acquired in November 2009 and increased other revenues.

Total Costs and Expenses. Total costs and expenses were $593.4 million for the three months ended June 30, 2010, which is an increase of $207.7 million, or 53.8%, from the corresponding period in 2009. Total costs and expenses reflect:

- an increase in refined petroleum product prices, which, coupled with an increase in volumes sold, resulted in a $299.7 million increase in the Energy Services segment s cost of product sales in the 2010 period as compared to the 2009 period;
- an increase of $6.9 million in the Natural Gas Storage segment s costs and expenses resulting from higher costs associated with hub services transactions recognized as expense caused primarily by general market conditions as discussed above;
- an increase in the Development & Logistics segment s costs and expenses due to $2.4 million of expenses related to the write-off in the 2010 period of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy; and
- an increase of $1.1 million in depreciation and amortization, primarily due to expense on assets placed in service in the second half of 2009 in connection with the Kirby Hills Phase II expansion project, and certain internal-use software, which was placed in service in the fourth quarter of 2009, and an increase of $1.1 million in non-cash unit-based compensation expense, neither of which are components of Adjusted EBITDA as presented in the reconciliation above.

Total costs and expenses in the 2009 period include the recognition of a non-cash $72.5 million asset impairment expense in the Pipeline Operations segment related to the Buckeye NGL Pipeline and $28.1 million of expenses across all segments associated with organizational restructuring, neither of which are components of

Table of Contents

Adjusted EBITDA as presented in the reconciliation above. These two charges were the primary cause of a partially offsetting decrease in total costs and expenses for the 2010 period as compared to the 2009 period. Total costs and expenses for the three months ended June 30, 2010 reflect the effectiveness of cost management efforts we implemented in 2009.

Total costs and expenses also reflect the following decreases:

- a decrease in costs and expenses of the Pipeline Operations segment, resulting substantially from a decrease related to the asset impairment expense and the organizational restructuring charges recognized in the 2009 period as discussed above and lower payroll and benefits costs, which was primarily attributable to the organizational restructuring that occurred in 2009 and resulted in reduced headcount, partially offset by increased integrity program expenses and increased professional fees; and
- a decrease in costs and expenses of the Terminalling & Storage segment, resulting primarily from a decrease related to expenses for organizational restructuring recognized in the 2009 period and decreased payroll and benefits costs, partially offset by higher environmental remediation expenses and higher operating expenses for terminals acquired in November 2009.

Consolidated net income attributable to unitholders. Consolidated net income attributable to our unitholders was $53.6 million for the three months ended June 30, 2010 compared to a net loss of $48.4 million for the three months ended June 30, 2009. Interest and debt expense increased by $5.2 million for the three months ended June 30, 2010 as compared to the corresponding period in 2009, which increase was largely attributable to the issuance in August 2009 of $275.0 million aggregate principal amount of 5.500% Notes due 2019 and higher outstanding borrowings under the BES Credit Agreement, partially offset by lower outstanding borrowings under our unsecured revolving credit agreement (the Credit Facility). In addition, depreciation and amortization increased by $1.1 million, primarily due to expense on assets placed in service in the second half of 2009 in connection with the Kirby Hills Phase II expansion project, and certain internal-use software, which was placed in service in the fourth quarter of 2009.

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

Pipeline Operations

Adjusted EBITDA. Adjusted EBITDA from the Pipeline Operations segment of $57.6 million for the three months ended June 30, 2010 decreased by $0.6 million, or 1.0%, from $58.2 million for the corresponding period in 2009. The decrease in Adjusted EBITDA was driven primarily by a decrease of $3.2 million in transportation revenues, resulting from lower volumes transported during the three months ended June 30, 2010 compared with the corresponding period in 2009. The decrease in volumes transported is partially attributable to the sale of the Buckeye NGL Pipeline on January 1, 2010 (see Note 2 in the Notes to Unaudited Condensed Consolidated Financial Statements). This decrease in Adjusted EBITDA was partially offset by a $2.4 million increase in other revenue, the benefit of higher tariffs of $1.9 million, favorable settlement experience of $1.0 million and increased revenue of $0.8 million from pipeline assets acquired in November 2009. The Pipeline Operations segment s decrease in Adjusted EBITDA was also due to a $0.3 million decrease in income from equity investments and a $3.1 million increase in operating expenses. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Pipeline Operations segment was $99.3 million for the three months ended June 30, 2010, which is an increase of $1.1 million, or 1.2%, from the corresponding period in 2009. Revenues increased due to the benefit of higher tariffs of $1.9 million, the result of overall average tariff increases of approximately 3.8% implemented on July 1, 2009 and 2.61% implemented on May 1, 2010. In addition, favorable settlement experience of $1.0 million, increased revenues of $0.8 million from pipeline assets acquired in November 2009 and increased other revenue of $2.4 million contributed to the increase in revenues. These increases in revenue were partially offset by a $3.2 million decrease related to a 2.5% decrease in transportation volumes due in part to the sale of the Buckeye NGL Pipeline on January 1, 2010 and reduced revenues of $1.3 million from a product supply arrangement with a wholesale distributor and contract service activities at customer facilities connected to our refined petroleum products pipelines pursuant to the assignment of such service contract to the Development & Logistics segment.

Total Costs and Expenses. Total costs and expenses from the Pipeline Operations segment were $53.9 million for the three months ended June 30, 2010, which is a decrease of $94.3 million, or 63.6%, from the corresponding period in 2009. Total costs and expenses for the 2009 period include a $72.5 million non-cash asset impairment expense and $23.1 million of expense related to an organizational restructuring. These charges in the 2009 period, which are not components of Adjusted EBITDA as presented in the reconciliation above, were the primary reason that costs and expenses in the 2009 period were 63.6% higher than in the 2010 period. Total costs and expenses for the three months ended June 30, 2010 also reflect an increase of $2.1 million in integrity program expenses, primarily due to increased levels of pipeline maintenance activities, and an increase of $0.7 million in professional fees, partially offset by a decrease of $1.3 million in payroll and benefits costs primarily related to our best practices initiative in 2009, and a decrease of $1.2 million in operating power costs due to lower transportation volumes and power contract renegotiations as part of our best practices initiative.

Operating Income. Operating income from the Pipeline Operations segment was $45.4 million for the three months ended June 30, 2010 compared to an operating loss of $50.0 million for the three months ended June 30, 2009. Other revenue and expense items impacting operating income are discussed above.

Terminalling & Storage

Adjusted EBITDA. Adjusted EBITDA from the Terminalling & Storage segment of $26.9 million for the three months ended June 30, 2010 increased by $11.4 million, or 73.4%, from $15.5 million for the corresponding period in 2009. The increase in Adjusted EBITDA reflects an increase of $10.7 million from the contribution of terminals acquired in November 2009, the impact of internal growth projects, increased throughput volumes, higher fees, increased storage, rental and other service revenue, increased settlement experience and a $0.7 million decrease in operating expenses. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Terminalling & Storage segment was $40.8 million for the three months ended June 30, 2010, which is an increase of $11.4 million, or 38.5%, from the corresponding period in 2009. Approximately $8.7 million of the increase resulted primarily from terminals acquired in November 2009, internal growth projects, increased throughput volumes, higher fees, higher storage and rental revenue, including $1.5 million in storage fees from previously underutilized tankage identified in connection with our best practices initiative and other marketing opportunities, and increased butane-blending revenue. Also contributing to the improved revenue was an increase of $2.6 million in settlement experience reflecting the favorable impact of higher refined petroleum product prices during the three months ended June 30, 2010 as compared to the corresponding period in 2009. In addition to the 13.8% increase in volumes resulting from the acquisition of terminals in November 2009, terminalling volumes increased 10.2% for the three months ended June 30, 2010 as compared to the corresponding period in 2009, largely due to increased ethanol throughput volumes.

Total Costs and Expenses. Total costs and expenses from the Terminalling & Storage segment were $16.5 million for the three months ended June 30, 2010, which is a decrease of $1.9 million, or 10.1%, from the corresponding period in 2009. The decrease in total costs and expenses in the 2010 period as compared to the 2009 period is due to a $2.4 million decrease related to expenses for organizational restructuring recognized in the 2009 period and a $1.1 million decrease in payroll and benefits costs primarily related to our best practices initiative in 2009. These decreases were partially offset by a $0.8 million increase in environmental remediation expenses, a $0.6 million increase in operating expenses for terminals acquired in November 2009 and a $0.5 million increase in depreciation and amortization. Depreciation and amortization and the organizational restructuring charges are not components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the Terminalling & Storage segment was $24.2 million for the three months ended June 30, 2010 compared to operating income of $11.0 million for the three months ended June 30, 2009. Depreciation and amortization increased by $0.5 million for the three months ended June 30, 2010 as a result

of the terminals acquired in November 2009. Other revenue and expense items impacting operating income are discussed above.

Natural Gas Storage

Adjusted EBITDA. Adjusted EBITDA from the Natural Gas Storage segment of $6.3 million for the three months ended June 30, 2010 decreased by $2.3 million, or 26.8%, from $8.6 million for the corresponding period in 2009. The decrease in Adjusted EBITDA was primarily the result of a $1.0 million decrease in the net contribution from hub service activities, a decrease of $0.6 million in lease revenues and an increase of $0.7 million in other operating expenses during the three months ended June 30, 2010. High storage inventory levels in the western region, above normal temperatures and general uncertainty regarding the economic recovery have added pressure on market-based lease fees charged for storage services, and therefore led to a decrease in the net contribution from hub services activities and decreased lease revenue. This decrease in lease revenues as a result of reduced fees was partially offset by increased storage capacity from the commissioning of the Kirby Hills Phase II expansion project, which was placed in service in June 2009. 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 $21.2 million for the three months ended June 30, 2010, which is an increase of $4.5 million, or 27.5%, from the corresponding period in 2009. This overall increase is attributable to greater underlying volume and higher fees recognized as revenue for hub services provided during the three months ended June 30, 2010. The fees for hub services agreements are based on the relative market prices of natural gas over different delivery periods. A positive market price spread results in receipt of a fee from the customer that is reflected as transportation and other services revenue. A negative market price spread results in payment of a fee to the customer that is reflected as cost of natural gas storage services. These fees are recognized as revenue or cost of natural gas storage services ratably as the underlying services are provided or utilized. Such agreements allow us to maximize the daily utilization of the natural gas storage facility and to attempt to capture value from seasonal price differences in the natural gas markets. During the three months ended June 30, 2010 and 2009, there were 165 and 150 outstanding hub service contracts, respectively, for which revenue was being recognized ratably. Market conditions contributed to higher fees of $5.2 million for hub service agreements recognized as revenue during the three months ended June 30, 2010 compared to the same period in 2009, partially offset by reduced market-based fees charged for storage services as a result of high storage inventory levels in the western region, above normal temperatures and general uncertainty regarding the economic recovery. Additionally, lease revenue decreased $0.6 million for the three months ended June 30, 2010, as a decrease in the fee charged for each volumetric unit of storage capacity leased was partially offset by increased storage capacity from the commissioning of the Kirby Hills Phase II expansion project, which was placed in service in June 2009.

Total Costs and Expenses. Total costs and expenses from the Natural Gas Storage segment were $17.8 million for the three months ended June 30, 2010, which is an increase of $6.9 million, or 63.9%, from the corresponding period in 2009. The primary driver of the increase in expenses is an increase in hub services fees paid to customers for hub service activities. As stated above, hub service fees are based on the relative market prices of natural gas over different delivery periods; a negative market price spread results in payment of a fee to the customer that is reflected as cost of natural gas storage services ratably as those services are provided. Other operating expenses increased $0.7 million, primarily due to increased fuel costs, professional fees, maintenance materials expense and rental expense. Total costs and expenses also include an increase of $0.5 million in depreciation and amortization, partially offset by a decrease of $0.3 million related to an organizational restructuring recognized in the 2009 period, neither of which are components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the Natural Gas Storage segment was $3.4 million for the three months ended June 30, 2010 compared to operating income of $5.8 million for the three months ended June 30, 2009. Depreciation and amortization increased by $0.5 million for the three months ended June 30, 2010 from the corresponding period in 2009 due to expense on assets placed in service in the second half of 2009 in connection with the Kirby Hills Phase II expansion project. Other revenue and expense items impacting operating income are discussed above.

Energy Services

Adjusted EBITDA. Adjusted EBITDA from the Energy Services segment of $1.3 million for the three months ended June 30, 2010 increased by $0.7 million, or 132.1%, from $0.6 million for the corresponding period in 2009. This increase in Adjusted EBITDA was primarily the result of a 75.4% increase in sales volumes, partially offset by lower margins for each gallon of product sold. The higher than normal levels of inventory for gasoline and distillate products industry-wide, in conjunction with an overall decline in demand has continued to suppress margins at the rack through the second quarter of 2010. In addition, contango opportunities in the market are at reduced levels as compared to the 2009 period which contributed to lower gross margin recognized during the 2010 period. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Energy Services segment was $501.9 million for the three months ended June 30, 2010, which is an increase of $300.2 million, or 148.9%, from the corresponding period in 2009. This increase was primarily due to an increase in refined petroleum product prices, which correspondingly increased the cost of product sales, and an increase of 75.4% in sales volumes.

Total Costs and Expenses. Total costs and expenses from the Energy Services segment were $502.1 million for the three months ended June 30, 2010, which is an increase of $298.9 million, or 147.2%, from the corresponding period in 2009. The increase in total costs and expenses was primarily due to an increase of $299.7 million in cost of product sales as a result of increased volumes sold and an increase in refined petroleum product prices, an increase of $0.4 million in payroll related costs and an increase of $0.4 million in bad debt expense, partially offset by a decrease of $0.7 million in maintenance materials expense and professional fees and a decrease of $0.9 million related to an organizational restructuring recognized in the 2009 period. The organizational restructuring charge is not a component of Adjusted EBITDA as presented in the reconciliation above.

Operating Income (loss). Operating loss from the Energy Services segment was $0.2 million for the three months ended June 30, 2010 compared to an operating loss of $1.5 million for the three months ended June 30, 2009. Depreciation and amortization increased by $0.2 million for the three months ended June 30, 2010 from the corresponding period in 2009 due to amortization of certain internal-use software that was placed in service in the fourth quarter of 2009. Other revenue and expense items impacting operating income (loss) are discussed above.

Development & Logistics

Adjusted EBITDA. Adjusted EBITDA from the Development & Logistics segment of $0.4 million for the three months ended June 30, 2010 decreased by $1.3 million, or 79.8%, from $1.7 million for the corresponding period in 2009, primarily due to the recognition of $2.4 million of expenses related to the write-off in the 2010 period of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy, and reduced operating contract margins of $0.2 million, partially offset by a net increase of $1.1 million related to the sale of ammonia linefill. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Development & Logistics segment, which consists principally of our contract operations and engineering services for third-party pipelines, was $10.8 million for the three months ended June 30, 2010, which is an increase of $2.0 million, or 22.5%, from the corresponding period in 2009. The increase in revenue was partially due to a $1.5 million increase in other revenue, primarily from the recognition of $1.1 million of revenue related to the sale of ammonia linefill. In addition, operating service revenues increased $2.2 million from the 2009 period, primarily due to the assignment of certain service contracts from the Pipeline Operations segment to the Development & Logistics segment. These increases in revenue were partially offset by the completion and non-replacement of construction projects in 2009, resulting in a $2.1 million reduction in certain construction contract revenues.

Total Costs and Expenses. Total costs and expenses from the Development & Logistics segment were $9.8 million for the three months ended June 30, 2010, which is an increase of $1.2 million, or 13.9%, from the corresponding period in 2009. The increase in total costs and expenses was the result of the recognition of $2.4 million of expenses related to the write-off in the 2010 period of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy, and increased operating services activities discussed above,

partially offset by reduced construction contract activity and lower income tax expense. Total costs and expenses also include a decrease of $1.4 million related to an organizational restructuring recognized in the 2009 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 $1.0 million for the three months ended June 30, 2010 compared to operating income of $0.2 million for the three months ended June 30, 2009. Income tax expense decreased by $0.7 million for the three months ended June 30, 2010 due to the recognition of a tax benefit of $0.6 million primarily related to the write-off of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy as discussed above. Other revenue and expense items impacting operating income are discussed above.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2009

Consolidated

Adjusted EBITDA. Adjusted EBITDA increased by $11.3 million, or 6.6%, to $182.6 million for the six months ended June 30, 2010 from $171.3 million for the corresponding period in 2009. The Terminalling & Storage segment and the Pipeline Operations segment were primarily responsible for this increase in Adjusted EBITDA. The Terminalling & Storage segment s Adjusted EBITDA increased by $24.7 million for the six months ended June 30, 2010 as compared to the corresponding period in 2009, driven by increased throughput volumes, growth in fees, storage and rental revenues, the contribution from terminals acquired in November 2009, favorable settlement experience and lower operating expenses. The Pipeline Operations segment s Adjusted EBITDA increased by $1.3 million for the six months ended June 30, 2010 as compared to the corresponding period in 2009, primarily due to increased tariffs and favorable settlement experience, which more than offset the impact of lower volumes transported during the six months ended June 30, 2010 compared to the corresponding period in 2009.

These increases in Adjusted EBITDA were partially offset by decreases in Adjusted EBITDA in the Energy Services segment, the Natural Gas Storage segment and the Development & Logistics segment. The Energy Services segment s Adjusted EBITDA decreased by $8.3 million for the six months ended June 30, 2010 as compared to the corresponding period in 2009, primarily due to lower margins realized on products sold as a result of weakened market conditions during the six months ended June 30, 2010, partially offset by increased volumes of products sold. The Natural Gas Storage segment s Adjusted EBITDA decreased by $4.8 million for the six months ended June 30, 2010 as compared to the corresponding period in 2009 as a result of high storage inventory levels in the western region, above normal temperatures and general uncertainty regarding the economic recovery which have added pressure on market-based lease fees charged for storage services, and therefore led to a decrease in the net contribution from hub services activities. The Development & Logistics segment s Adjusted EBITDA decreased by $1.8 million for the six months ended June 30, 2010 as compared to the corresponding period in 2009, due to $2.4 million of expenses related to the write-off in the 2010 period of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy and due to reduced operating and construction contract services.

Overall, Adjusted EBTIDA was also impacted favorably by the continued effectiveness of cost control measures we implemented in 2009. Largely as a result of these efforts, costs decreased by approximately $9.4 million during the six months ended June 30, 2010 as compared to the corresponding period in 2009. Income from equity investments increased by $0.2 million for the six months ended June 30, 2010 as compared to the corresponding period in 2009. The revenue and expense factors affecting the variance in consolidated Adjusted EBITDA are more fully discussed below.

Revenue. Revenue was $1,398.5 million for the six months ended June 30, 2010, which is an increase of $630.4 million, or 82.1%, from the six months ended June 30, 2009. The increase in revenue for the six months ended June 30, 2010 as compared to the corresponding period in 2009 was caused primarily by the following:

- an increase of $600.0 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 six months ended June 30, 2010 as compared to the corresponding period in 2009;

- an increase of $23.0 million in revenue from the Terminalling & Storage segment, resulting from increased throughput volumes, increased fees, storage and rental revenue, including $3.2 million in storage fees from previously underutilized tankage identified in connection with our best practices initiative and other marketing opportunities, increased revenue from the contribution of terminals acquired in November 2009 and favorable settlement experience;
- an increase of $15.0 million in revenue from the Natural Gas Storage segment, resulting primarily from higher fees from hub services transactions recognized as revenue; and
- an increase of $0.4 million in revenue from the Development & Logistics segment, resulting primarily from the sale of ammonia linefill.

The increase in revenue was partially offset by:

- a decrease of $1.5 million in revenue from the Pipeline Operations segment, resulting primarily from lower transportation volumes and lower other revenue, partially offset by increased tariffs, favorable settlement experience and increased revenues from the contribution of pipeline assets acquired in November 2009.

Total Costs and Expenses. Total costs and expenses were $1,253.6 million for the six months ended June 30, 2010, which is an increase of $521.1 million, or 71.1%, from the corresponding period in 2009. Total costs and expenses reflect:

- an increase in refined petroleum product prices, which, coupled with an increase in volume sold, resulted in a $609.6 million increase in the Energy Services segment s cost of product sales in the 2010 period as compared to the 2009 period;
- an increase of $20.0 million in the Natural Gas Storage segment s costs and expenses resulting from higher costs associated with hub services transactions recognized as expense caused primarily by general market conditions as discussed above;
- an increase of $2.2 million in depreciation and amortization, primarily due to expense on assets placed in service in the second half of 2009 in connection with the Kirby Hills Phase II expansion project, and certain internal-use software, which was placed in service in the fourth quarter of 2009, and an increase of $2.3 million in non-cash unit-based compensation expense, neither of which are components of Adjusted EBITDA as presented in the reconciliation above; and
- no significant change in the Development & Logistics segment s costs and expenses from the 2009 period to the 2010 period, as $2.4 million of expenses related to the write-off in the 2010 period of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy and increased operating services activities in the 2010 period were substantially offset by a decrease of $1.4 million related to an organizational restructuring recognized in the 2009 period and reduced construction contract activity in the 2010 period.

Total costs and expenses in the 2009 period include the recognition of a non-cash $72.5 million asset impairment expense in the Pipeline Operations segment, related to the Buckeye NGL Pipeline and $28.1 million of expenses across all segments associated with organizational restructuring, none of which are components of Adjusted EBITDA as presented in the reconciliation above. These two charges were the primary cause of a partially offsetting decrease in total costs and expenses for the 2010 period as compared to the 2009 period. Total costs and expenses for the six months ended June 30, 2010 reflect the effectiveness of cost management efforts we implemented in 2009.

Total costs and expenses also reflect the following decreases:

- a decrease in costs and expenses of the Pipeline Operations segment, resulting substantially from a decrease related to the asset impairment expense and the organizational restructuring charges recognized in the 2009 period as discussed above and lower payroll and benefits costs, which was primarily attributable to the organizational restructuring that occurred in 2009 and resulted in reduced headcount, as well as from lower contract service activities, lower environmental remediation expenses, lower contract service activities and lower operating power costs due to lower transportation volumes and power contract renegotiations as part of our best practices initiative; and

a decrease in costs and expenses of the Terminalling & Storage segment, resulting primarily from a decrease related to expenses for organizational restructuring recognized in the 2009 period, lower environmental remediation expenses and lower payroll and benefits costs, partially offset by higher operating expense for terminals acquired in November 2009 and higher bad debt expense.

Consolidated net income attributable to unitholders. Consolidated net income attributable to our unitholders was $104.1 million for the six months ended June 30, 2010 compared to $5.4 million for the six months ended June 30, 2009. Interest and debt expense increased by $9.6 million for the six months ended June 30, 2010 as compared to the corresponding period in 2009, which increase was largely attributable to the issuance in August 2009 of $275.0 million aggregate principal amount of 5.500% Notes due 2019, higher outstanding borrowings under the BES Credit Agreement and lower interest capitalized on construction projects, partially offset by lower outstanding borrowings under the Credit Facility. In addition, depreciation and amortization increased by $2.2 million, primarily due to expense on assets placed in service in the second half of 2009 in connection with the Kirby Hills Phase II expansion project and certain internal-use software, which was placed in service in the fourth quarter of 2009.

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

Pipeline Operations

Adjusted EBITDA. Adjusted EBITDA from the Pipeline Operations segment of $115.4 million for the six months ended June 30, 2010 increased by $1.3 million, or 1.2%, from $114.1 million for the corresponding period in 2009. The increase in Adjusted EBITDA was driven primarily by the benefit of higher tariffs of $4.6 million, favorable settlement experience of $3.0 million, increased revenues of $1.4 million from pipeline assets acquired in November 2009, a $1.4 million increase in other net revenues and a $0.2 million increase in income from equity investments. These increases in Adjusted EBITDA were partially offset by an $8.9 million decrease in transportation revenues resulting from lower volumes transported during the six months ended June 30, 2010 compared with the corresponding period in 2009 and lower volumes resulting from the sale of the Buckeye NGL Pipeline on January 1, 2010, and a $0.4 million increase in operating expenses. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Pipeline Operations segment was $195.9 million for the six months ended June 30, 2010, which is a decrease of $1.5 million, or 0.8%, from the corresponding period in 2009. Revenues decreased by $8.9 million, resulting from a 4.0% decrease in transportation volumes, due in part to the sale of the Buckeye NGL Pipeline on January 1, 2010 and a $2.2 million decrease in revenue from a product supply arrangement with a wholesale distributor and contract service activities at customer facilities connected to our refined petroleum products pipelines pursuant to the assignment of such service contract to the Development & Logistics segment. These decreases in revenue were partially offset by higher tariffs of $4.6 million, the result of overall average tariff increases of approximately 3.8% implemented on July 1, 2009 and 2.61% implemented on May 1, 2010, favorable settlement experience of $3.0 million and increased revenues of $1.4 million from pipeline assets acquired in November 2009.

Total Costs and Expenses. Total costs and expenses from the Pipeline Operations segment were $104.5 million for the six months ended June 30, 2010, which is a decrease of $98.0 million, or 48.4%, from the corresponding period in 2009. Total costs and expenses for the 2009 period include a $72.5 million non-cash asset impairment expense and $23.1 million of expense related to organizational restructuring. These charges in the six months ended June 30, 2009 were the primary reason that total costs and expenses in the 2009 period were 48.4% higher than in the 2010 period. The asset impairment expense and the organizational restructuring charges are not components of Adjusted EBITDA as presented in the reconciliation above.

In addition, total costs and expenses in the 2010 period were lower than in the 2009 period as a result of a $3.3 million decrease in payroll and benefits costs, resulting primarily from our best practices initiative, a $1.5 million reduction in environmental remediation expenses, a $1.3 million decrease in operating power costs due to lower transportation volumes and power contract renegotiations as part of our best practices initiative, a $1.2 million decrease in contract service activities at customer facilities connected to our refined petroleum products pipelines, and a $0.8 million decrease in product costs, resulting from reduced volumes of product sold to a wholesale distributor. These decreases in total costs and expenses were partially offset by an increase of $4.7 million in professional fees and other expenses, including an increase of $2.2 million in integrity program expenses and an increase of $0.6 million in bad debt expense.

Operating Income. Operating income from the Pipeline Operations segment was $91.4 million for the six months ended June 30, 2010 compared to an operating loss of $5.1 million for the six months ended June 30, 2009. Income from equity investments increased by $0.2 million for the six months ended June 30, 2010 as compared to the corresponding period in 2009. Other revenue and expense items impacting operating income are discussed above.

Terminalling & Storage

Adjusted EBITDA. Adjusted EBITDA from the Terminalling & Storage segment of $53.1 million for the six months ended June 30, 2010 increased by $24.7 million, or 87.2%, from $28.4 million for the corresponding period in 2009. The increase in Adjusted EBITDA reflects an increase of $21.9 million from the contribution of terminals acquired in November 2009, the impact of internal growth projects, increased throughput volumes, higher fees, increased storage, rental and other service revenue, increased settlement experience and a $2.8 million decrease in operating expenses. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Terminalling & Storage segment was $83.1 million for the six months ended June 30, 2010, which is an increase of $23.0 million, or 38.4%, from the corresponding period in 2009. Approximately $19.5 million of the increase resulted primarily from terminals acquired in November 2009, internal growth projects, increased throughput volumes, higher fees, higher storage and rental revenue, including $3.2 million in storage fees from previously underutilized tankage identified in connection with our best practices initiative and other marketing opportunities, and increased butane-blending revenue. Also contributing to the improved revenue was an increase of $3.5 million in settlement experience, reflecting the favorable impact of higher refined petroleum product prices during the six months ended June 30, 2010 as compared to the corresponding period in 2009. In addition to the 12.1% increase in volumes resulting from the acquisition of terminals in November 2009, terminalling volumes increased 7.6% for the six months ended June 30, 2010 as compared to the corresponding period in 2009, largely due to increased ethanol throughput volumes.

Total Costs and Expenses. Total costs and expenses from the Terminalling & Storage segment were $35.4 million for the six months ended June 30, 2010, which is a decrease of $2.6 million, or 6.8%, from the corresponding period in 2009. The decrease in total costs and expenses in the 2010 period as compared to the 2009 period is due to a $2.4 million decrease related to expenses for organizational restructuring recognized in the 2009 period, a $1.5 million decrease in environmental remediation expenses and a $1.5 million decrease in payroll and benefits costs primarily related to our best practices initiative in 2009, partially offset by a $1.3 million increase in operating expenses for terminals acquired in November 2009, a $0.6 million increase in bad debt expense and a $1.1 million increase in depreciation and amortization, primarily due to expense on assets acquired in November 2009. Depreciation and amortization and the organizational restructuring charges are not components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the Terminalling & Storage segment was $47.7 million for the six months ended June 30, 2010 compared to operating income of $22.0 million for the six months ended June 30, 2009. Depreciation and amortization increased by $1.1 million for the six months ended June 30, 2010 as a result of the terminals acquired in November 2009. Other revenue and expense items impacting operating income are discussed above.

Natural Gas Storage

Adjusted EBITDA. Adjusted EBITDA from the Natural Gas Storage segment of $12.7 million for the six months ended June 30, 2010 decreased by $4.8 million, or 27.3%, from $17.5 million for the corresponding period in 2009. The decrease in Adjusted EBITDA was primarily the result of a $4.9 million decrease in the net

Table of Contents

contribution from hub service activities and an increase of $0.6 million in operating expenses, partially offset by an increase of $0.8 million in lease revenues during the six months ended June 30, 2010. The increase in lease revenues was the result of increased storage capacity from the commissioning of the Kirby Hills Phase II expansion project, which was placed in service in June 2009, partially offset by a decrease in the fee charged for each volumetric unit of storage capacity leased. 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 $46.7 million for the six months ended June 30, 2010, which is an increase of $15.0 million, or 46.9%, from the corresponding period in 2009. This overall increase is attributable to greater underlying volume and higher fees recognized as revenue for hub services provided during the six months ended June 30, 2010. During the six months ended June 30, 2010 and 2009, there were 232 and 205 outstanding hub service contracts, respectively, for which revenue was being recognized ratably. Market conditions contributed to higher fees of $14.1 million for hub service agreements recognized as revenue during the six months ended June 30, 2010 as compared to the corresponding period in 2009. Lease revenue also increased $0.8 million for the six months ended June 30, 2010, as increased storage capacity from the commissioning of the Kirby Hills Phase II expansion project, which was placed in service in June 2009, was partially offset by 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 $39.7 million for the six months ended June 30, 2010, which is an increase of $20.0 million, or 101.2%, from the corresponding period in 2009. The primary driver of the increase in expenses is an increase in hub services fees paid to customers for hub service activities. Other operating expenses increased by $0.6 million, primarily due to increased fuel costs, professional fees, maintenance materials expense and supplies and rental expenses, partially offset by decreased outside service costs. Total costs and expenses also include an increase of $0.6 million in depreciation and amortization, partially offset by a decrease of $0.3 million related to organizational restructuring charges recognized in the 2009 period, neither of which are components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the Natural Gas Storage segment was $7.0 million for the six months ended June 30, 2010 compared to operating income of $12.0 million for the six months ended June 30, 2009. Depreciation and amortization increased by $0.6 million for the six months ended June 30, 2010 from the corresponding period in 2009 due to expense on assets placed in service in the second half of 2009 in connection with the Kirby Hills Phase II expansion project. Other revenue and expense items impacting operating income are discussed above.

Energy Services

Adjusted EBITDA. Adjusted EBITDA from the Energy Services segment decreased by $8.3 million, or 102.4%, to a loss of $0.2 million during the six months ended June 30, 2010 compared with income of $8.1 million for the corresponding period in 2009. This decrease in Adjusted EBITDA was a result of the withdrawal of product from inventory as market conditions changed and commodity prices were no longer in contango. The increase in product supply in the market place from inventory liquidation, coupled with lower overall product demand, created additional pressure on margins, which was partially offset by a 58.4% increase in Energy Services sales volume. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Energy Services segment was $1,070.2 million for the six months ended June 30, 2010, which is an increase of $600.0 million, or 127.6%, from the corresponding period in 2009. This increase was primarily due to an increase in refined petroleum product prices in the 2010 period, which correspondingly increased the cost of product sales, and an increase of 58.4% in sales volumes.

Total Costs and Expenses. Total costs and expenses from the Energy Services segment were $1,073.4 million for the six months ended June 30, 2010, which is an increase of $608.2 million, or 130.7%, from the corresponding period in 2009. The increase in total costs and expenses was primarily due to an increase of $609.6 million in cost of product sales as a result of increased volumes sold and an increase in refined petroleum product prices and an increase of $0.7 million in bad debt expense, partially offset by a decrease of $1.4 million in maintenance materials expense and professional fees. Total costs and expenses also include an increase of $0.5 million in depreciation and

amortization, partially offset by a decrease of $0.9 million related to an organizational restructuring recognized in the 2009 period, neither of which are components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income (loss). Operating loss from the Energy Services segment was $3.2 million for the six months ended June 30, 2010 compared to operating income of $4.9 million for the six months ended June 30, 2009. Depreciation and amortization increased by $0.5 million for the six months ended June 30, 2010 from the corresponding period in 2009 due to amortization of certain internal-use software that was placed in service in the fourth quarter of 2009. Other revenue and expense items impacting operating income (loss) are discussed above.

Development & Logistics

Adjusted EBITDA. Adjusted EBITDA from the Development & Logistics segment of $1.5 million for the six months ended June 30, 2010 decreased by $1.8 million, or 54.4%, from $3.3 million for the corresponding period in 2009, primarily due to reduced construction contract margins of $2.5 million and reduced operating contract margins of $0.4 million, partially offset by a net increase of $1.2 million related to the sale of ammonia linefill. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Development & Logistics segment was $18.3 million for the six months ended June 30, 2010, which is an increase of $0.4 million, or 2.1%, from the corresponding period in 2009. The increase in revenue was partially due to the recognition of $1.2 million of revenue related to the sale of ammonia linefill. In addition, operating service revenues increased by $2.0 million from the 2009 period, primarily due to the assignment of certain service contracts from the Pipeline Operations segment to the Development & Logistics segment. These increases in revenue were partially offset by reduced construction contract activity following completion of certain construction projects in 2009, resulting in a $3.6 million reduction in certain construction contract revenues.

Total Costs and Expenses. Total costs and expenses from the Development & Logistics segment were $16.2 million for the six months ended June 30, 2010, which is consistent with the corresponding period in 2009. Total costs and expenses include $1.4 million of expense related to an organizational restructuring recognized in the 2009 period, which is not a component of Adjusted EBITDA as presented in the reconciliation above. Total costs and expenses increased as a result of the recognition of $2.4 million of expenses related to the write-off in the 2010 period of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy, and increased operating services activities discussed above, partially offset by reduced contract construction activity discussed above and lower income tax expense.

Operating Income. Operating income from the Development & Logistics segment was $2.1 million for the six months ended June 30, 2010 compared to operating income of $1.7 million for the six months ended June 30, 2009. Income tax expense decreased by $0.8 million for the six months ended June 30, 2010, primarily due to the recognition of a tax benefit of $0.6 million primarily related to the write-off of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy as discussed above. Other 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 LP Units. We will, from time to time, issue debt securities to permanently finance amounts borrowed under the Credit Facility. BES funds its working capital needs principally from its operations and the BES Credit Agreement. 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 the Credit Facility 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.

As a result of our actions to minimize external financing requirements and the fact that no debt facilities mature prior to 2011, we believe that availabilities under our credit facilities, coupled with ongoing cash flows from operations, will be sufficient to fund our operations for the remainder of 2010. We will continue to evaluate a variety of financing sources, including the debt and equity markets described above, throughout 2010. However, continuing volatility in the debt and equity markets will make the timing and cost of any such potential financing uncertain.

At June 30, 2010, we had $12.5 million of cash and cash equivalents on hand and approximately $580.0 million of available credit under the Credit Facility, after application of the facility s funded debt ratio covenant. In addition, at June 30, 2010, BES had $20.6 million of available credit under the BES Credit Agreement, pursuant to certain borrowing base calculations under that agreement.

At June 30, 2010, we had an aggregate face amount of $1,619.2 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);
- $150.0 million of 6.750% Notes due 2033 (the 6.750% Notes); and
- $194.2 million outstanding under the BES Credit Agreement.

See Note 10 in the Notes to Unaudited Condensed Consolidated Financial Statements for more information about the terms of the debt discussed above.

The fair values of our aggregate debt and credit facilities were estimated to be $1,672.6 million and $1,762.1 million at June 30, 2010 and December 31, 2009, 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.

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 would allow us to issue an unlimited amount of debt and equity securities for general partnership purposes.

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):

	Six Months Ended June 30,	
	2010	**2009**
Cash provided by (used in):		
Operating activities	$ 233,779	$ 102,577
Investing activities	(5,298)	(43,678)
Financing activities	(250,567)	(95,745)

Operating Activities

Net cash flow provided by operating activities was $233.8 million for the six months ended June 30, 2010 compared to $102.6 million for the six months ended June 30, 2009. The following were the principal factors resulting in the $131.2 million increase in net cash flows provided by operating activities:

- The net change in fair values of derivatives was a decrease of $12.9 million to cash flows from operating activities for the six months ended June 30, 2010, resulting from the increase in value related to fixed-price sales contracts compared to a lower level of opposite fluctuations in futures contracts purchased to hedge such fluctuations.
- The net impact of working capital changes was an increase of $96.2 million to cash flows from operating activities for the six months ended June 30, 2010. The principal factors affecting the working capital changes were:
  - Prepaid and other current assets decreased by $36.7 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 six months ended June 30, 2010 (increased commodity prices result in an increase in our broker equity account and therefore less margin deposit is required), a decrease in unbilled revenue within our Natural Gas Storage segment reflecting billings to counterparties in accordance with terms of their storage agreements, a decrease in receivables related to ammonia contracts and a decrease in prepaid insurance due to continued amortization of the balance over the policy period.
  - Inventories decreased by $28.1 million due to a decrease in volume of hedged inventory stored by the Energy Services segment. From time to time, the Energy Services segment stores hedged inventory to attempt to capture value when market conditions are economically favorable.
  - Trade receivables decreased by $10.6 million primarily due to the timing of collections from customers, partially offset by increased activity from our Energy Services segment due to higher volumes and higher commodity prices in the 2010 period.
  - Accrued and other current liabilities increased by $10.8 million primarily due to increases in unearned revenue primarily in the Natural Gas Storage segment as a result of increased hub services contracts during the six months ended June 30, 2010 for which the customer is billed up front for services provided over the entire term of the contract, partially offset by the payment of accrued ammonia purchases during the period and a reduction in the reorganization accrual.
  - Accounts payable increased by $7.6 million primarily due to higher payable balances at June 30, 2010 as a result of increased trading activity at BES resulting from increased volumes and increased commodity prices during the period.
  - Construction and pipeline relocation receivables decreased by $2.5 million primarily due to a decrease in construction activity in the 2010 period.

Investing Activities

Net cash flow used in investing activities was $5.3 million for the six months ended June 30, 2010 compared to $43.7 million for the six months ended June 30, 2009. The following were the principal factors resulting in the $38.4 million decrease in net cash flows used in investing activities:

- Capital expenditures decreased by $12.2 million for the six months ended June 30, 2010 compared with the six months ended June 30, 2009. See below for a discussion of capital spending.
- We contributed $3.9 million to West Texas LPG Pipeline Limited Partnership in the six months ended June 30, 2009 for our pro-rata share of an expansion project required to meet increased pipeline demand caused by increased product production in the Fort Worth basin and East Texas regions.
- Cash proceeds from the sale of the Buckeye NGL Pipeline were $22.0 million during the six months ended June 30, 2010.

Table of Contents

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

	Six Months Ended June 30,	
	2010	2009
Sustaining capital expenditures	$ 9,195	$ 7,773
Expansion and cost reduction	18,377	32,046
Total capital expenditures, net	$ 27,572	$ 39,819

Expansion and cost reduction projects in the first six months of 2010 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 operating infrastructure projects. In the first six months of 2009, expansion and cost reduction projects included the Kirby Hills Phase II expansion project, terminal ethanol and butane blending, the construction of three additional tanks with capacity of 0.4 million barrels in Linden, New Jersey and various other pipeline and terminal operating infrastructure projects.

We expect to spend approximately $75.0 million to $95.0 million for capital expenditures in 2010, of which approximately $25.0 million to $35.0 million is expected to relate to sustaining capital expenditures and $50.0 million to $60.0 million is expected to relate to expansion and cost reduction projects. Sustaining capital expenditures include renewals and 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 2010 will include the completion of additional product storage tanks in the Midwest, various terminal expansions and upgrades and pipeline and terminal automation projects.

Financing Activities

Net cash flow used in financing activities was $250.6 million for the six months ended June 30, 2010 compared to $95.7 million for the six months ended June 30, 2009. The following were the principal factors resulting in the $154.9 million increase in net cash flows used in financing activities:

- We borrowed $95.0 million and $77.3 million and repaid $173.0 million and $166.6 million under the Credit Facility during the six months ended June 30, 2010 and 2009, respectively.
- Net repayments under the BES Credit Agreement were $45.6 million during the six months ended June 30, 2010, while net borrowings under the BES Credit Agreement were $3.0 million during the six months ended June 30, 2009.
- We incurred $3.2 million of debt issuance costs during the six months ended June 30, 2010 related to the amendment to the BES Credit Agreement in June 2010 (see Note 10 in the Notes to Unaudited Condensed Consolidated Financial Statements).
- We received $3.0 million in net proceeds from the exercise of LP Unit options during the six months ended June 30, 2010. We received $104.8 million in net proceeds from an underwritten equity offering in March and April of 2009 for the public issuance of 3.0 million LP Units.
- Cash distributions paid to our partners increased by $11.3 million period-to-period due to an increase in the number of LP Units outstanding and an increase in our quarterly cash distribution rate per LP Unit. We paid cash distributions of $122.9 million ($1.8875 per LP Unit) and $111.6 million ($1.7875 per LP Unit) during the six months ended June 30, 2010 and 2009, respectively.
- We paid $1.3 million of costs associated with the Merger during the six months ended June 30, 2010.

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.

Table of Contents

Other Considerations

Contractual Obligations

With the exception of routine fluctuations in the balance of the Credit Facility and the BES Credit Agreement, there have been no material changes in our scheduled maturities of our debt obligations since those reported in our Annual Report on Form 10-K for the year ended December 31, 2009.

Total rental expense for the three months ended June 30, 2010 and 2009 was $5.5 million and $5.1 million, respectively. For the six months ended June 30, 2010 and 2009, total rental expense was $10.5 million and $10.3 million, respectively. There have been no material changes in our operating lease commitments since those reported in our Annual Report on Form 10-K for the year ended December 31, 2009.

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 for the year ended December 31, 2009.

Related Party Transactions

With respect to related party transactions, see Note 16 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 and do not engage in hedging activity with respect to trading instruments.

Market Risk Non-Trading Instruments

We are exposed to financial market risk resulting from changes in commodity prices and interest rates. We do not currently have foreign exchange risk.

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.

Table of Contents

As of June 30, 2010, the Natural Gas Storage segment has recorded the following assets and liabilities related to its hub services agreements (in thousands):

	June 30, 2010
Assets:	
Hub service agreements	$ 32,394
Liabilities:	
Hub service agreements	(26,750)
Total	$ 5,644

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 fixed-price 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 fixed-price sales contracts. Therefore, our fixed-price sales contracts and the related futures contracts used to offset those fixed-price sales contracts are all marked-to-market on the condensed consolidated balance sheet with gains and losses being recognized in earnings during the period.

As of June 30, 2010, the Energy Services segment had derivative assets and liabilities as follows (in thousands):

	June 30, 2010
Assets:	
Fixed-price sales contracts	$ 5,121
Futures contracts for inventory and fixed-price sales contracts	4,973
Liabilities:	
Fixed-price sales contracts	(166)
Futures contracts for inventory and fixed-price sales contracts	(202)
Total	$ 9,726

Our hedged inventory portfolio extends to the first quarter of 2011. The majority of the unrealized income at June 30, 2010 for inventory hedges represented by futures contracts will be realized by the third quarter of 2010 as the related inventory is sold. Gains recorded on inventory hedges that were ineffective were approximately $1.0 million and $5.8 million for the three and six months ended June 30, 2010, respectively. At June 30, 2010, open refined petroleum product derivative contracts (represented by the fixed-price sales contracts and futures contracts for fixed-price sales contracts and inventory noted above) varied in duration, but did not extend beyond October 2011. In addition, at June 30, 2010, we had refined petroleum product inventories which we intend to use to satisfy a portion of the fixed-price sales contracts.

54

Based on a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at June 30, 2010, 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	$ 9,726
Fair value assuming 10% increase in underlying commodity prices	Liability	$ (3,589)
Fair value assuming 10% decrease in underlying commodity prices	Asset	$ 23,044

The value of the open futures contract positions noted above were based upon quoted market prices obtained from NYMEX. The value of the fixed-price sales 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 refined petroleum product inventories and its fixed-price sales 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 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 January 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 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.

At June 30, 2010, we had total fixed-rate debt obligations at face value of $1,425.0 million, consisting of $125.0 million of the 5.125% Notes, $275.0 million of the 5.300% Notes, $300.0 million of the 4.625% Notes, $150.0 million of the 6.750% Notes, $300.0 million of the 6.050% Notes and $275.0 million of the 5.500% Notes. The fair value of these fixed-rate debt obligations at June 30, 2010 was approximately $1,478.4 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 $87.3 million.

Table of Contents

At June 30, 2010, our variable-rate obligation was $194.2 million under the BES Credit Agreement. Based on the balance outstanding at June 30, 2010, we estimate that a 1% increase or decrease in interest rates would increase or decrease annual interest expense by approximately $1.9 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. During 2009, we entered into four forward-starting interest rate swaps with a total aggregate notional amount of $200.0 million related to the anticipated issuance of debt on or before July 15, 2013 and three forward-starting interest rate swaps with a total aggregate notional amount of $150.0 million related to the anticipated issuance of debt on or before October 15, 2014. During the three months ended June 30, 2010, we entered into two forward-starting interest rate swaps with a total aggregate notional amount of $100.0 million related to the anticipated issuance of debt on or before July 15, 2013 and three forward-starting interest rate swaps with a total aggregate notional amount of $125.0 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 and six months ended June 30, 2010, unrealized losses of $34.9 million and $36.2 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. 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.

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 June 30, 2010 (in thousands):

Scenario	**Resulting Classification**	**Financial Instrument Portfolio Fair Value**
Fair value assuming no change in underlying interest rates (as is)	Liability	$ (18,953)
Fair value assuming 10% increase in underlying interest rates	Asset	$ 414
Fair value assuming 10% decrease in underlying interest rates	Liability	$ (39,148)

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.

Table of Contents

(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 second quarter of 2010, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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 below and in Part 1, Item 1A. Risk Factors of our Annual Report on Form 10-K for the year ended December 31, 2009 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.

While the Merger Agreement is in effect, BGH s opportunities to enter into different business combination transactions with other parties on more favorable terms may be limited, and both we and BGH may be limited in our ability to pursue other attractive business opportunities.

While the Merger Agreement is in effect, BGH is prohibited from knowingly initiating, soliciting or encouraging the submission of any acquisition proposal or from participating in any discussions or negotiations regarding any acquisition proposal, subject to certain exceptions. As a result of these provisions in the Merger Agreement, BGH s opportunities to enter into more favorable transactions may be limited. Likewise, if BGH were to sell directly to a third party, it might have received more value with respect to the general partner interest in us and the incentive distribution rights in us based on the value of the business at such time.

Moreover, the Merger Agreement provides for the payment of up to $29.0 million in termination fees under specified circumstances, which may discourage other parties from proposing alternative transactions that could be more favorable to the BGH unitholders or our unitholders.

Both we and BGH have also agreed to refrain from taking certain actions with respect to our businesses and financial affairs pending completion of the Merger or termination of the Merger Agreement. These restrictions could be in effect for an extended period of time if completion of the Merger is delayed. These limitations do not preclude us from conducting our business in the ordinary or usual course or from acquiring assets or businesses so long as such activity does not have a material adverse effect as such term is defined in the Merger Agreement or materially affect our or BGH s ability to complete the transactions contemplated by the Merger Agreement.

In addition to the economic costs associated with pursuing the Merger, the management of BGH s general partner and our general partner will continue to devote substantial time and other human resources to the proposed Merger, which could limit BGH s and our ability to pursue other attractive business opportunities, including potential joint ventures, stand-alone projects and other transactions. If either we or BGH are unable to pursue such other attractive business opportunities, then our growth prospects and the long-term strategic position of our businesses following the Merger could be adversely affected.

Our existing unitholders will be diluted by the Merger.

The Merger will dilute the ownership position of our existing unitholders. Pursuant to the Merger Agreement, BGH s unitholders will receive approximately 20.0 million of our LP Units as a result of the Merger. Immediately following the Merger, we will be owned approximately 72% by our current unitholders and approximately 28% by former BGH unitholders.

The number of our outstanding LP Units will increase as a result of the Merger, which could make it more difficult to pay the current level of quarterly distributions.

As of August 3, 2010, there were approximately 51.5 million of our LP Units outstanding. We will issue approximately 20.0 million of our LP Units in connection with the Merger. Accordingly, the dollar amount required to pay the current per LP Unit quarterly distributions will increase, which will increase the likelihood that we will not have sufficient funds to pay the current level of quarterly distributions to all of our unitholders. Using the amount of $0.9625 per LP Unit declared with respect to the second quarter of 2010, the aggregate cash distribution to be paid to our unitholders will total approximately $49.6 million, resulting in a distribution of $13.1 million to our general partner for its general partner units and incentive distribution rights. Therefore, our combined total distribution to be paid with respect to the second quarter of 2010 will be $62.7 million. Pursuant to the Merger Agreement, BGH unitholders will receive approximately 20.0 million of our LP Units as a result of the Merger. Our combined pro forma distribution with respect to the second quarter 2010, had the Merger been completed prior to such distribution, would result in $0.9625 per LP Unit being distributed on approximately 71.5 million of our LP Units, or a total of $68.8 million, with our general partner no longer receiving any distributions. As a result, we would be required to distribute an additional $6.1 million per quarter in order to maintain the distribution level of $0.9625 per LP Unit paid with respect to the second quarter of 2010.

Although the elimination of the incentive distribution rights may increase the cash available for distribution to our LP Units in the future, this source of funds may not be sufficient to meet the overall increase in cash required to maintain the current level of quarterly distributions to holders of our LP Units.

Failure to complete the Merger or delays in completing the Merger could negatively impact our LP Unit price and the BGH unit price.

If the Merger is not completed for any reason, we and BGH may be subject to a number of material risks, including the following:

- we will not realize the benefits expected from the Merger, including a potentially enhanced financial and competitive position;

- the price of our LP Units or BGH units may decline to the extent that the current market price of these securities reflects a market assumption that the Merger will be completed; and

- some costs relating to the Merger, such as certain investment banking fees and legal and accounting fees, must be paid even if the Merger is not completed.

The costs of the Merger could adversely affect our operations and cash flows available for distribution to our unitholders.

We and BGH estimate the total costs of the Merger to be approximately $12.0 million, primarily consisting of investment banking and legal advisors fees, accounting fees, financial printing and other related costs. These costs could adversely affect our operations and cash flows available for distributions to our unitholders. The foregoing estimate is preliminary and is subject to change.

Tax Risks Related to the Merger

No ruling has been obtained with respect to the tax consequences of the Merger.

No ruling has been or will be requested from the Internal Revenue Service (IRS) with respect to the tax consequences of the Merger. Instead, we and BGH are relying on the opinions of our respective counsel as to the tax consequences of the Merger, and counsel s conclusions may not be sustained if challenged by the IRS.

Table of Contents

The intended tax consequences of the Merger are dependent upon our and BGH being treated as partnerships for tax purposes.

The treatment of the Merger as nontaxable to our unitholders and BGH s unitholders is dependent upon each of us and BGH being treated as a partnership for federal income tax purposes. If either we or BGH were treated as a corporation for federal income tax purposes, the consequences of the Merger would be materially different and the Merger would likely be a fully taxable transaction to a BGH unitholder.

Tax Risks to Existing Buckeye Unitholders

An existing holder of our LP Units may be required to recognize a gain as a result of the decrease in its allocable share of our nonrecourse liabilities as a result of the Merger.

As a result of the Merger, the allocable share of nonrecourse liabilities allocated to our existing unitholders will be recalculated to take into account the LP Units issued by us in the Merger. If an existing holder of our LP Units experiences a reduction in its share of our nonrecourse liabilities as a result of the Merger, which is referred to as a reducing debt shift, such holder will be deemed to have received a cash distribution equal to the amount of the reduction. A reduction in a unitholder s share of our liabilities will result in a corresponding basis reduction in such unitholder s LP Units. A reducing debt shift and the resulting deemed cash distribution may, under certain circumstances, result in the recognition of taxable gain by a holder of our LP Units, to the extent that the deemed cash distribution exceeds such unitholder s tax basis in its LP Units. Although we have not received an opinion with respect to the shift of nonrecourse liabilities, we do not expect that any constructive cash distribution will exceed any existing unitholder s tax basis in its LP Units.

We estimate that the Merger will result in an increase in the amount of net income (or decrease in the amount of net loss) allocable to all of our existing unitholders.

We estimate that the closing of the Merger will result in an increase in the amount of net income (or decrease in the amount of net loss) allocable to all of our existing unitholders. In addition, the federal income tax liability of an existing unitholder could be further increased if we make a future offering of LP Units and use the proceeds of the offering in a manner that does not produce substantial additional deductions, such as to repay indebtedness currently outstanding or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes or that is depreciable or amortizable at a rate significantly slower than the rate currently applicable to our assets.

Table of Contents

Item 6. ***Exhibits***

(a) Exhibits

2.1	Agreement and Plan of Merger, dated June 10, 2010, by and among Buckeye Partners, L.P., Buckeye GP LLC, Buckeye GP Holdings L.P., MainLine Management LLC and Grand Ohio, LLC, a subsidiary of Buckeye Partners, L.P. (Incorporated by reference to Exhibit 2.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on June 11, 2010).
*10.1	Buckeye Partners, L.P. Annual Incentive Compensation Plan, as Amended and Restated, effective as of May 6, 2010 (Incorporated by reference to Exhibit 10.15 of Buckeye Partners, L.P. s Registration Statement on Form S-4 filed on July 14, 2010).
10.2	Amended and Restated Credit Agreement, dated as of June 25, 2010, among Buckeye Energy Services LLC, BNP Paribas 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 July 1, 2010).
10.3	Support 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 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on June 11, 2010).
10.4	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).
**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.

*

Represents management contract or compensatory plan or arrangement.

** 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.

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: August 6, 2010	By: /s/ Keith E. St.Clair Keith E. St.Clair Senior Vice President and Chief Financial Officer *(Principal Accounting Officer and Principal Financial Officer)*