BUCKEYE PARTNERS, L.P.
Form 10-K
February 26, 2010

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

(Mark One)

þ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the fiscal year ended December 31, 2009

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

Title of each class	**Name of each exchange on which registered**
Limited partner units representing limited partnership interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

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

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

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 website, if any, every Interactive Date 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 o No o

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

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

At June 30, 2009, the aggregate market value of the registrant s limited partner units held by non-affiliates was $2.1 billion. The calculation of such market value should not be construed as an admission or conclusion by the registrant that any person is in fact an affiliate of the registrant.

Limited partner units outstanding as of February 19, 2010: 51,464,265

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information contained in this Annual Report on Form 10-K (this Report) include forward-looking statements. All statements that express belief, expectation, estimates or intentions, as well as those that are not statements of historical facts, are forward-looking statements. Such statements use forward-looking words such as proposed, anticipate, project, potential, could, should, continue, estimate, expect, may, believe, will, plan, seek, outlook and other similar expressions that are intended to identify forward-looking statements, although some forward-looking statements are expressed differently. These statements discuss future expectations and contain projections. Specific factors that could cause actual results to differ from those in the forward-looking statements include, but are not limited to: (1) price trends and overall demand for refined petroleum products and natural gas in the United States in general and in our service areas in particular (economic activity, weather, alternative energy sources, conservation and technological advances may affect price trends and demands); (2) competitive pressures from other transportation services or alternative fuel sources; (3) changes, if any, in laws and regulations, including, among others, safety, environmental, tax and accounting matters or Federal Energy Regulatory Commission regulation of our tariff rates; (4) liability for environmental claims; (5) security issues affecting our assets, including, among others, potential damage to our assets caused by vandalism, acts of war or terrorism; (6) construction costs, unanticipated capital expenditures and operating expenses to repair or replace our assets; (7) nonpayment or nonperformance by our customers; (8) our ability to successfully identify, complete and integrate strategic acquisitions and make cost saving changes in operations; (9) expansion in the operations of our competitors; (10) shut-downs or production cutbacks at major refineries that use our services; (11) deterioration in our labor relations; (12) changes in real property tax assessments; (13) regional economic conditions; (14) disruptions to the air travel system; (15) interest rate fluctuations and other capital market conditions; (16) market conditions in our industry; (17) availability and cost of insurance on our assets and operations; (18) conflicts of interest between us, our general partner, the owner of our general partner and its affiliates; (19) the treatment of us as a corporation for federal income tax purposes or if we become subject to entity-level taxation for state tax purposes; and (20) our ability to realize the anticipated benefits of our organizational restructuring. These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other known or unpredictable factors could also have material adverse effects on future results. Consequently, all of the forward-looking statements made in this document are qualified by these cautionary statements, and we cannot assure you that actual results or developments that we anticipate will be realized or, even if substantially realized, will have the expected consequences to or effect on us or our business or operations. Also note that we provide additional cautionary discussion of risks and uncertainties under the captions Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this Report.

The forward-looking statements contained in this Report speak only as of the date hereof. Although the expectations in the forward-looking statements are based on our current beliefs and expectations, we do not assume responsibility for the accuracy and completeness of such statements. 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. All forward-looking statements attributable to us or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in this Report and in our future periodic reports filed with the U.S. Securities and Exchange Commission (SEC). In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this Report may not occur.

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PART I

Item 1. *Business*

Introduction

The original Buckeye Pipe Line Company was founded in 1886 as part of the Standard Oil Company and became a publicly owned, independent company after the dissolution of Standard Oil in 1911. Expansion into petroleum products transportation after World War II and subsequent acquisitions thereafter ultimately led to Buckeye Pipe Line Company becoming a leading independent common carrier pipeline. In 1964, Buckeye Pipe Line Company was acquired by a subsidiary of the Pennsylvania Railroad, which later became the Penn Central Corporation. In 1986, Buckeye Pipe Line Company was reorganized into a master limited partnership (MLP), Buckeye Partners, L.P. We are a publicly traded Delaware partnership, and our limited partner units (LP Units) are listed on the New York Stock Exchange (NYSE) under the ticker symbol BPL. Buckeye GP LLC (Buckeye GP) is our general partner. Buckeye GP is a wholly-owned subsidiary of Buckeye GP Holdings L.P. (BGH), a Delaware MLP that is separately traded on the NYSE under the ticker symbol BGH. Unless the context requires otherwise, references to *we*, *us*, *our*, the *Partner* or *Buckeye* are intended to mean the business and operations of Buckeye Partners, L.P. and its consolidated subsidiaries.

We have 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 chemical companies. We also own and operate a major natural gas storage facility in northern California, which provides approximately 40 billion cubic feet (Bcf) of total natural gas storage capacity (including pad gas), 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 and Storage; Natural Gas Storage; Energy Services; and Development and Logistics. We previously referred to the Development and Logistics segment as the Other Operations segment. We renamed this segment to better describe the business activities conducted within the segment. We conduct all of our operations through our operating subsidiaries, which are referred to herein as our *Operating Subsidiaries* :

Buckeye Pipe Line Company, L.P. (Buckeye Pipe Line), which owns an approximately 2,643-mile refined petroleum products pipeline system serving major population centers in eight states. As a part of its service territory, Buckeye Pipe Line is the primary jet fuel transporter to certain airports, including John F. Kennedy International Airport (JFK Airport), LaGuardia Airport and Newark Liberty International Airport (Newark Airport).

Laurel Pipe Line Company, L.P. (Laurel), which owns an approximately 345-mile refined petroleum products pipeline connecting four Philadelphia area refineries to ten delivery points across Pennsylvania.

Wood River Pipe Lines LLC (Wood River), which owns eight refined petroleum products pipelines with aggregate mileage of approximately 1,287 miles located in Illinois, Indiana, Missouri and Ohio. Wood River includes two pipelines that we acquired from ConocoPhillips in November 2009. See 2009 Developments below for further information.

Buckeye Pipe Line Transportation LLC (BPL Transportation), which owns a refined petroleum products pipeline system with aggregate mileage of approximately 478 miles located in New Jersey, New York and Pennsylvania.

Everglades Pipe Line Company, L.P. (Everglades), which owns an approximately 37-mile refined petroleum products pipeline connecting Port Everglades, Florida to Ft. Lauderdale-Hollywood International Airport and Miami International Airport. Everglades is the primary jet fuel transporter to Miami International Airport.

Buckeye Pipe Line Holdings, L.P. (BPH), which, through certain of its subsidiaries, owns (or in certain instances leases from our other Operating Subsidiaries) 62 refined petroleum and other products terminals (of which 59 are included in our Terminalling and Storage segment and three are included in our Pipeline Operations segment) with aggregate storage capacity of approximately 26.2 million barrels and 574 miles of pipelines in the Midwest and West Coast. BPH s terminal holdings include three terminals that we acquired from ConocoPhillips in November 2009. See 2009 Developments below for further information. BPH operates, through its subsidiaries, terminals and pipelines for third parties. BPH also holds noncontrolling stock interests in two Midwest refined petroleum products pipelines and a natural gas liquids (NGLs) pipeline system.

Buckeye Gas Storage LLC (Buckeye Gas), which, through its subsidiary Lodi Gas Storage, L.L.C. (Lodi Gas), owns a natural gas storage facility in northern California that provides approximately 40 Bcf of total natural gas storage capacity (including pad gas).

Buckeye Energy Holdings LLC (Buckeye Energy), which, through its subsidiary Buckeye Energy Services LLC (BES), markets refined petroleum products in areas served by our pipelines and terminals and also owns five refined petroleum product terminals with aggregate storage capacity of 1.0 million barrels located in northeastern and central Pennsylvania.

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The following chart depicts our and BGH s ownership structure as of December 31, 2009 (ownership percentages in the chart are approximate).

Business Strategy

Our primary business objective is to provide stable and sustainable cash distributions to the holders of our LP Units (Unitholders), while maintaining a relatively low investment risk profile. The key elements of our strategy are to:

- Generate stable cash flows;
- Improve operating efficiencies and asset utilization;
- Generate increased cash distributions to our Unitholders;
- Grow our portfolio of predictable and stable fee-based businesses combined with opportunistic revenue generating capabilities;
- Operate in a safe and environmentally responsible manner; and
- Maintain an investment-grade credit rating.

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We intend to achieve our strategy by:

- Acquiring, building and operating high quality, strategically located assets;
- Maintaining stable long-term customer relationships, including by providing superior customer service;
- Maintaining and enhancing the integrity of our pipelines, terminals and storage assets;
- Maintaining a solid, conservative financial position;
- Optimizing our portfolio of pipeline, terminalling and storage assets;
- Pursuing strategic cash flow accretive acquisitions that:
  - Complement our existing footprint;
  - Provide geographic, product and/or asset class diversity;
  - Leverage existing management capabilities and infrastructure; and
- Building an experienced management team with the objective to grow our business.

2009 Developments

Reorganization

In early 2009, we began a best practices review of our business processes and organizational structure to identify improved business practices, operating efficiencies and cost savings in anticipation of changing needs in the energy markets. This review culminated in the approval by the Board of Directors of Buckeye GP of an organizational restructuring.

The organizational restructuring included a workforce reduction of approximately 230 employees, in excess of 20% of our workforce. The program was initiated in the second quarter of 2009 and was substantially complete by the end of 2009. As part of the workforce reduction, we offered certain eligible employees the option of enrolling in a voluntary early retirement program, which approximately 80 employees accepted. The remaining affected positions have been eliminated involuntarily under our ongoing severance plan. Most terminations were effective as of July 20, 2009. The restructuring also included the relocation of some employees consistent with the goals of the reorganization. We have incurred $32.1 million of expenses in connection with this organizational restructuring for the year ended December 31, 2009. See Note 3 in the Notes to Consolidated Financial Statements for further discussion.

Asset Impairment and Subsequent Sale of the Assets

During the second quarter of 2009, we received notification that several of the shippers on the NGL pipeline owned by Buckeye NGL Pipe Lines LLC (Buckeye NGL) intended to migrate their business to a competing pipeline that recently went into service. In connection with this notification, there was a significant decline in shipment volumes as compared to historical averages. This significant loss in the customer base utilizing our NGL pipeline, in conjunction with the authorization by the Board of Directors of Buckeye GP to pursue the sale of Buckeye NGL, triggered an evaluation of a potential asset impairment that resulted in a non-cash charge to earnings of $72.5 million in the Pipeline Operations segment in the second quarter of 2009. Effective January 1, 2010, we sold our ownership interest in Buckeye NGL for $22.0 million. The sales proceeds exceeded the previously impaired carrying value of the assets of Buckeye NGL by $12.8 million resulting in the reversal of $12.8 million of the previously recorded asset impairment expense in the fourth quarter of 2009. The impairment and subsequent reversal are reflected within the category Asset Impairment Expense on our consolidated statements of operations. See Note 8 in the Notes to Consolidated Financial Statements for further discussion.

Refined Petroleum Product Terminals and Pipeline Assets Acquisition

In November 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 for $7.3 million and entered into certain commercial contracts with ConocoPhillips that are associated with the acquired facilities. The assets that we acquired include over 300 miles of active pipelines that provide connectivity between the East St. Louis, Illinois and East Chicago, Indiana markets and three terminals providing 2.3 million barrels of storage. We funded the acquisition through cash flows from operations and borrowings under our existing credit facility. See Note 4 in the Notes to Consolidated Financial Statements for further discussion.

Completion of Kirby Hills Phase II Expansion Project

In June 2009, we completed the Kirby Hills Phase II expansion project. The Kirby Hills Phase II expansion project provides approximately 100,000 million cubic feet per day (MMcf/day) of additional injection capability and 200,000 MMcf/day of additional withdrawal capability at Lodi Gas s natural gas storage facility. See Natural Gas Storage Segment below for further information.

Debt Financings

In August 2009, we sold $275.0 million aggregate principal amount of 5.500% Notes due 2019 (the 5.500% Notes) in an underwritten public offering. The notes were issued at 99.35% of their principal amount. Total proceeds from this offering, after underwriters fees, expenses and debt issuance costs of $1.8 million, were approximately $271.4 million, and were used to reduce amounts outstanding under our credit facility and for general partnership purposes.

In August 2009, we amended the BES credit agreement (BES Credit Agreement) to increase the borrowing capacity from $175.0 million to $250.0 million. Our unsecured revolving credit agreement (the Credit Facility) was also amended to reduce the borrowing capacity from $600.0 million to $580.0 million. See Note 13 in the Notes to Consolidated Financial Statements for further discussion.

Equity Offering

On March 31, 2009, we issued 2.6 million LP Units in an underwritten public offering at $35.08 per LP Unit. On April 29, 2009, the underwriters of the equity offering exercised their option to purchase an additional 390,000 LP Units at $35.08 per LP Unit. Total proceeds from the offering, including the overallotment option and after the underwriter s discount of $1.17 per LP Unit and offering expenses, were approximately $104.6 million, and were used to reduce amounts outstanding under our Credit Facility.

2009 LTIP

In March 2009, the 2009 Long-Term Incentive Plan of Buckeye Partners, L.P. (the 2009 LTIP) became effective after the approval by a majority of our Unitholders. The 2009 LTIP, which is administered by the Compensation Committee of the Board of Directors of Buckeye GP (the Compensation Committee), provides for the grant of phantom units, performance units and, in certain cases, distribution equivalent rights (DERs), which provide the participant a right to receive payments based on distributions we make on our LP Units. The number of LP Units that may be granted under the 2009 LTIP may not exceed 1,500,000 subject to certain adjustments.

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 2009 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 (AIC Plan) or other discretionary bonus programs 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. See Note 18 in the Notes to Consolidated Financial Statements for further discussion.

Business Activities

The following discussion describes the business activities of our business segments for 2009, which include Pipeline Operations, Terminalling and Storage, Natural Gas Storage, Energy Services, and Development and Logistics. The Pipeline Operations and Energy Services segments derive a nominal amount of their revenue from U.S. governmental agencies. Otherwise, none of our business segments have contracts or subcontracts with the U.S.

government. All of our assets are located in the continental United States. Detailed financial information regarding revenues, operating income and total assets of each segment can be found in Note 23 in the Notes to Consolidated Financial Statements. The following table shows our consolidated revenues and each segment s percentage of consolidated revenue for the periods indicated (revenue in thousands):

	Year Ended December 31,					
	2009		2008		2007	
	Revenue	Percent	Revenue	Percent	Revenue	Percent
Pipeline Operations	$ 392,667	22.3%	$ 387,267	20.4%	$ 379,345	73.0%
Terminalling and Storage	136,576	7.7%	119,155	6.3%	103,782	20.0%
Natural Gas Storage	99,163	5.6%	61,791	3.3%		
Energy Services	1,125,013	63.5%	1,295,925	68.3%		
Development and Logistics	34,136	1.9%	43,498	2.3%	36,220	7.0%
Intersegment	(17,183)	-1.0%	(10,984)	-0.6%		
Total revenue	$ 1,770,372	100.0%	$ 1,896,652	100.0%	$ 519,347	100.0%

Pipeline Operations Segment

The Pipeline Operations segment owns and operates approximately 5,400 miles of pipeline located primarily in the northeastern and upper midwestern portions of the United States and services approximately 100 delivery locations. This segment transports refined petroleum products, including gasoline, jet fuel, diesel fuel, heating oil and kerosene, from major supply sources to terminals and airports located within end-use markets. The pipelines within this segment also transport other refined petroleum products, such as propane and butane, refinery feedstock and blending components. The segment s geographical diversity, connections to multiple sources of supply and extensive delivery system help create a stable base business.

The Pipeline Operations segment conducts business without the benefit of exclusive franchises from government entities. In addition, the Pipeline Operations segment generally operates as a common carrier, providing transportation services at posted tariffs and without long-term contracts. Demand for the services provided by the Pipeline Operations segment derives from end users demand for refined petroleum products in the regions served and the ability and willingness of refiners and marketers to supply such demand by deliveries through our pipelines. Factors affecting demand for refined petroleum products include price and prevailing general economic conditions. Demand for the services provided by the Pipeline Operations segment is, therefore, subject to a variety of factors partially or entirely beyond our control. Typically, this segment s pipelines receive refined petroleum products from refineries, connecting pipelines, and bulk and marine terminals and transport those products to other locations for a fee.

The following table shows the volume and percentage of refined petroleum products transported by the Pipelines Operations segment for the periods indicated (volume in thousands of barrels per day):

	Year Ended December 31,					
	2009		2008		2007	
	Volume	Percent	Volume	Percent	Volume	Percent
Gasoline	650.1	49.6%	673.5	48.7%	717.9	49.6%
Jet fuel	336.7	25.7%	354.7	25.7%	362.7	25.1%
Middle distillates (1)	284.7	21.7%	304.2	22.0%	320.1	22.1%
NGLs (2)	13.9	1.1%	20.9	1.5%	20.4	1.4%
Other products	24.5	1.9%	28.9	2.1%	26.3	1.8%
Total (3)	1,309.9	100.0%	1,382.2	100.0%	1,447.4	100.0%

(1) Includes diesel fuel, heating oil, kerosene and other middle distillates.

(2) Represents volumes transported by the Buckeye NGL pipeline, which we sold effective January 1, 2010.

(3) Excludes local product transfers.

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We provide pipeline transportation services in the following states: California, Connecticut, Florida, Illinois, Indiana, Massachusetts, Michigan, Missouri, Nevada, New Jersey, New York, Ohio, Pennsylvania, Tennessee and Texas. The geographical location and description of these pipelines is as follows:

Pennsylvania New York New Jersey

Buckeye Pipe Line serves major population centers in Pennsylvania, New York and New Jersey through approximately 928 miles of pipeline. Refined petroleum products are received at Linden, New Jersey from 17 major source points, including two refineries, six connecting pipelines and nine storage and terminalling facilities. Products are then transported through two lines from Linden, New Jersey to Macungie, Pennsylvania. From Macungie, the pipeline continues west through a connection with the Laurel pipeline to Pittsburgh, Pennsylvania (serving Reading, Harrisburg, Altoona/Johnstown and Pittsburgh, Pennsylvania) and north through eastern Pennsylvania into New York (serving Scranton/Wilkes-Barre, Pennsylvania and Binghamton, Syracuse, Utica, Rochester and, via a connecting carrier, Buffalo, New York). We lease capacity in one of the pipelines extending from Pennsylvania to upstate New York to a major oil pipeline company. Products received at Linden, New Jersey are also transported through one line to Newark Airport and through two additional lines to JFK Airport and LaGuardia Airport and to commercial refined petroleum products terminals at Long Island City and Inwood, New York. These pipelines supply JFK Airport, LaGuardia Airport and Newark Airport with substantially all of each airport s jet fuel requirements.

BPL Transportation s pipeline system delivers refined petroleum products from Valero Energy Corporation s (Valero) refinery located in Paulsboro, New Jersey to destinations in New Jersey, Pennsylvania and New York. A portion of the pipeline system extends from Paulsboro, New Jersey to Malvern, Pennsylvania. From Malvern, a pipeline segment delivers refined petroleum products to locations in upstate New York, while another segment delivers products to central Pennsylvania. Two shorter pipeline segments connect Valero s refinery to the Colonial pipeline system and the Philadelphia International Airport, respectively.

The Laurel pipeline system transports refined petroleum products through a 345-mile pipeline extending westward from four refineries and a connection to the Colonial pipeline system in the Philadelphia area to Reading, Harrisburg, Altoona/Johnstown and Pittsburgh, Pennsylvania.

Illinois Indiana Michigan Missouri Ohio

Buckeye Pipe Line and NORCO Pipe Line Company, LLC (NORCO), a subsidiary of BPH, transport refined petroleum products through 2,025 miles of pipeline in northern Illinois, central Indiana, eastern Michigan, western and northern Ohio, and western Pennsylvania. A number of receiving lines and delivery lines connect to a central corridor which runs from Lima, Ohio through Toledo, Ohio to Detroit, Michigan. Refined petroleum products are received at a refinery and other pipeline connection points near Toledo and Lima, Ohio; Detroit, Michigan; and East Chicago, Indiana. Major market areas served include Peoria, Illinois; Huntington/Fort Wayne, Indianapolis and South Bend, Indiana; Bay City, Detroit and Flint, Michigan; Cleveland, Columbus, Lima and Toledo, Ohio; and Pittsburgh, Pennsylvania.

Wood River owns eight refined petroleum products pipelines with aggregate mileage of approximately 1,287 miles located in the midwestern United States. Refined petroleum products are received from ConocoPhillips Wood River refinery in Illinois and transported to the Chicago area, to our terminal in the St. Louis, Missouri area and to the Lambert-St. Louis Airport, to receiving points across Illinois and Indiana and to our pipeline in Lima, Ohio. Petroleum products are also transported from the East St. Louis, Illinois area to the East Chicago, Indiana area with delivery points in Illinois and Indiana, and from the East Chicago, Indiana area to the Kankakee, Illinois area. At our tank farm located in Hartford, Illinois, one of Wood River s pipelines also receives refined petroleum products from the Explorer pipeline, which are transported to our 1.3 million barrel terminal located on the Ohio River in Mt. Vernon, Indiana. Wood River also owns an approximately 26-mile pipeline that extends from Marathon Pipe Line LLC s (Marathon) Wood River Station in southern Illinois to the East St. Louis, Illinois area.

Other Refined Petroleum Products Pipelines

Buckeye Pipe Line serves Connecticut and Massachusetts through an approximately 112-mile pipeline that carries refined petroleum products from New Haven, Connecticut to Hartford, Connecticut and Springfield, Massachusetts. This pipeline also serves Bradley International Airport in Windsor Locks, Connecticut.

Everglades transports primarily jet fuel through an approximately 37-mile pipeline from Port Everglades, Florida to Ft. Lauderdale-Hollywood International Airport and Miami International Airport. Everglades supplies Miami International Airport with substantially all of its jet fuel requirements.

WesPac Pipelines Reno LLC (WesPac Reno) owns an approximately 3.0-mile pipeline serving the Reno/Tahoe International Airport. WesPac Pipelines San Diego LLC (WesPac San Diego) owns an approximately 4.3-mile pipeline serving the San Diego International Airport. WesPac Pipelines Memphis LLC (WesPac Memphis) owns an approximately 11-mile pipeline and a related terminal facility that primarily serves Federal Express Corporation at the Memphis International Airport. WesPac Reno, WesPac San Diego and WesPac Memphis, collectively, have terminal facilities with aggregate storage capacity of 0.5 million barrels. Each of WesPac Reno, WesPac San Diego and WesPac Memphis was originally created as a joint venture between BPH and Kealine LLC (Kealine). BPH currently owns 100% of WesPac Reno and WesPac San Diego. BPH and Kealine each have a 50% ownership interest in WesPac Memphis. As of December 31, 2009, we had provided $43.9 million in intercompany financing to WesPac Memphis. Each of these entities has been consolidated into our financial statements.

Equity Investments

BPH owns a 25% equity interest in West Shore Pipe Line Company (West Shore). West Shore owns an approximately 652-mile pipeline system that originates in the Chicago, Illinois area and extends north to Green Bay, Wisconsin and west and then north to Madison, Wisconsin. The pipeline system transports refined petroleum products to markets in northern Illinois and Wisconsin. The other equity holders of West Shore are major oil companies. Prior to January 1, 2009, the West Shore pipeline system was operated by Citgo Pipeline Company. Effective January 1, 2009, we have assumed the operations of the West Shore pipeline system on behalf of West Shore.

BPH also owns a 20% equity interest in West Texas LPG Pipeline Limited Partnership (WT LPG). WT LPG owns an approximately 2,295-mile pipeline system that delivers raw mix NGLs to Mont Belvieu, Texas for fractionation. The NGLs are delivered to the WT LPG pipeline system from the Rocky Mountain region via connecting pipelines and from gathering fields and plants located in west, central and east Texas. The majority owner and the operator of WT LPG are affiliates of Chevron Corporation.

BPH also owns a 40% equity interest in Muskegon Pipeline LLC (Muskegon). Marathon is the majority owner and operator of Muskegon. Muskegon owns an approximately 170-mile pipeline that delivers petroleum products from Griffith, Indiana to Muskegon, Michigan.

Buckeye Pipe Line owns a 25% equity interest in Transport4, LLC (Transport4). Transport4 provides an internet-based shipper information system that allows its customers, including shippers, suppliers and tankage partners to access nominations, schedules, tickets, inventories, invoices and bulletins over a secure internet connection.

Terminalling and Storage Segment

The Terminalling and Storage segment owns 59 terminals that provide bulk storage and throughput services with respect to refined petroleum products and other renewable fuels, including ethanol, and has an aggregate storage capacity of approximately 25.7 million barrels. Of our 59 terminals in the Terminalling and Storage segment, 45 are connected to our pipelines and 14 are not. We own the property on which the terminals are located with the exception of the Albany terminal, which is primarily located on leased property.

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The Terminalling and Storage segment s terminals receive products from pipelines and, in certain cases, barges and railroads, and distribute them to third parties, who in turn deliver them to end-users and retail outlets. This segment s terminals play a key role in moving products to the end-user market by providing efficient product receipt, storage and distribution capabilities, inventory management, ethanol and biodiesel blending, and other ancillary services that include the injection of various additives. Typically, the Terminalling and Storage segment s terminal facilities consist of multiple storage tanks and are equipped with automated truck loading equipment that is available 24 hours a day.

The segment s terminals derive most of their revenues from various fees paid by customers. A throughput fee is charged for receiving products into the terminal and delivering them to trucks, barges or pipelines. In addition to these throughput fees, revenues are generated by charging customers fees for blending with renewable fuels, injecting additives and leasing terminal capacity to customers on either a short-term or long-term basis. The terminals also derive revenue from recovering and selling vapors emitted during truck loading.

The following table sets forth the total average daily throughput for the Terminalling and Storage segment s products terminals for the periods indicated (volume in average barrels per day):

	Year Ended December 31,		
	2009	**2008**	**2007**
Products throughput (1)	444,900	457,400	482,300

(1) Reported quantities exclude transfer volumes, which are non-revenue generating transfers among our various terminals. For the years ended December 31, 2008 and 2007, we previously reported 537.7 thousand and 568.6 thousand barrels, respectively, which included transfer volumes.

The following table sets forth the number of terminals and storage capacity in barrels by state for terminals reported in the Terminalling and Storage segment as of December 31, 2009:

State	**Number of Terminals (1)**	**Storage Capacity (000s Barrels)**
Connecticut	1	345
Illinois	9	3,161

Indiana	10	8,910
Massachusetts	1	106
Michigan	11	3,992
Missouri	2	345
New York	10	4,111
Ohio	8	2,871
Pennsylvania	4	1,131
Wisconsin	3	734
Total	59	25,706

(1) In addition, we have three terminals which are included in the Pipelines Operations segment for reporting purposes. There is a terminal in each of the states of California (with storage capacity of 0.1 million barrels), Nevada (with storage capacity of 0.1 million barrels) and Tennessee (with storage capacity of 0.3 million barrels). We also have five terminals in Pennsylvania with aggregate storage capacity of approximately 1.0 million barrels. These terminals are included in the Energy Services segment for reporting purposes (as

discussed
below).

Natural Gas Storage Segment

The Natural Gas Storage segment provides natural gas storage services through a facility located in northern California, which we acquired in January 2008, when we purchased all of the member interests in Lodi Gas for approximately $442.4 million. Currently, the facility provides approximately 40 Bcf of total natural gas storage capacity (including pad gas) and is connected to Pacific Gas and Electric s intrastate gas pipeline system that services natural gas demand in the San Francisco and Sacramento, California areas.

The original Lodi Gas facility is located approximately 30 miles south of Sacramento, near Lodi, California, and has been in service since January 2002. Its two storage reservoirs have daily maximum injection and withdrawal capability of 400 MMcf/day and 500 MMcf/day, respectively, utilizing 15 wells. Thirty-one miles of pipeline links the facility to an interconnect with Pacific Gas and Electric just north of Antioch, California.

In January 2007, prior to our acquisition of Lodi Gas, Lodi Gas completed the Kirby Hills Phase I expansion. Kirby Hills is located approximately 30 miles west of Lodi in the Montezuma Hills, nine miles southeast of Fairfield, California. The Kirby Hills Phase I expansion added maximum injection and withdrawal capability of 50 MMcf/day utilizing six wells. Six miles of pipeline links the facility to an interconnect with Pacific Gas and Electric approximately six miles west of Rio Vista, California.

In June 2009, we completed the Kirby Hills Phase II expansion project. The Kirby Hills Phase II expansion project provides approximately 100,000 MMcf/day of additional injection capability and 200,000 MMcf/day of additional withdrawal capability at Lodi Gas natural gas storage facility.

The Natural Gas Storage segment s operations are designed for overall high deliverability natural gas storage service and have a proven track record of safe and reliable operations. This segment is regulated by the California Public Utilities Commission. All services have been, and will continue to be, contracted under the Natural Gas Storage segment s published California Public Utilities Commission tariff.

The Natural Gas Storage segment s revenues consist of lease revenues and hub services revenues. Lease revenues are charges for the reservation of storage space for natural gas. Generally, customers inject natural gas in the fall and spring and withdraw it for winter and summer use. Title to the stored gas remains with the customer. Hub services revenues consist of a variety of other storage services under interruptible storage agreements. The Natural Gas Storage segment does not trade or market natural gas.

Energy Services Segment

In February 2008, we acquired all of the member interests in Farm & Home Oil Company LLC (Farm & Home) for approximately $146.2 million. When Farm & Home was acquired, it also had retail operations, but we sold those operations in April 2008. The acquisition of Farm & Home s wholesale operations provided an opportunity for us to increase the utilization of our existing pipeline and terminal system infrastructure by marketing refined petroleum products in areas served by that infrastructure.

The Energy Services segment is a wholesale distributor of refined petroleum products in the United States in areas also served by our pipelines and terminals. The segment s products include gasoline, propane and petroleum distillates such as heating oil, diesel fuel and kerosene. The segment has five terminals with aggregate storage capacity of approximately 1.0 million barrels. Each terminal is equipped with multiple storage tanks and automated truck loading equipment that is available 24 hours a day. We own the property on which the terminals are located.

The following table sets forth the total gallons of refined petroleum products sold by the Energy Services segment for the periods indicated (in thousands):

	Year Ended December 31,	
	2009	**2008**
Sales volumes	655,100	435,200

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The Energy Services segment s operations are segregated into three separate categories based on the type of fuel delivered and the delivery method:

Wholesale Rack liquid fuels and propane gas are delivered to distributors and large commercial customers. These customers take delivery of the products using the Energy Services segment s automated truck loading equipment to fill their own trucks.

Wholesale Delivered liquid fuels are delivered to commercial customers, construction companies, school districts and trucking companies using third-party carriers.

Branded Gasoline the Energy Services segment delivers, through third-party carriers, gasoline and on-highway diesel fuel to independently owned retail gas stations under many leading gasoline brands.

Since the operations of the Energy Services segment exposes us to commodity price risk, the Energy Services segment enters into derivative instruments to mitigate the effect of commodity price fluctuations on the segment s inventory and fixed-priced sales contracts. The fair value of our derivative instruments is recorded in our consolidated balance sheet, with the change in fair value recorded in earnings. The derivative instruments the Energy Services segment uses consist primarily of futures contracts traded on the New York Mercantile Exchange (NYMEX) for the purposes of hedging the outright price risk of its physical inventory and fixed-priced sales contracts. However, hedge accounting has not been used for all of the Energy Services segment s derivative instruments. In the cases in which hedge accounting has not been used, changes in the fair values of the derivative instrument, which are included in cost of product sales, generally are offset by changes in the values of the fixed-priced sales contracts which are also derivative instruments whose changes in value are recognized in product sales. The Energy Services segment records revenues when products are delivered.

Development and Logistics Segment

The Development and Logistics segment consists primarily of terminal and pipeline operations and maintenance services and related construction services for third parties. The Development and Logistics segment is a contract operator of pipelines and terminals primarily located in Texas and Louisiana that are owned by major oil and gas, petrochemical and chemical companies. At December 31, 2009, our Development and Logistics segment had performance obligations under existing multi-year arrangements to operate and maintain approximately 2,400 miles of pipeline. Further, this segment owns an approximate 23-mile pipeline located in Texas and leases a portion of the pipeline to a third-party chemical company. The Development and Logistics segment also owns an approximately 63% interest in a crude butadiene pipeline between Deer Park, Texas and Port Arthur, Texas and owns and operates an ammonia pipeline located in Texas. In addition, the Development and Logistics segment provides engineering and construction management services to major chemical companies in the Gulf Coast area.

We plan to continue the third-party contract operation and maintenance business in this segment, but we also intend to grow our footprint and asset capabilities through this segment by leveraging our project development capabilities, commercial management and operational competency and focusing on expanding outside our existing service area of pipeline and terminal assets through the provision of comprehensive project development services, including idea origination, securing necessary funding for the project, construction of the assets, and operations and commercial management following the project s completion.

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Competition and Customers

Competitive Strengths

We believe that we have the following competitive strengths:

- We operate in a safe and environmentally responsible manner;
- We own and operate high quality assets that are strategically located;
- We have stable, long-term relationships with our customers;
- We own relatively predictable and stable fee-based businesses with opportunistic revenue generating capabilities;
- We maintain a conservative financial position with an investment-grade credit rating; and
- We have an experienced management team whose interests are aligned with those of our Unitholders.

Pipeline Operations and Terminalling and Storage Segments

Generally, pipelines are the lowest cost method for long-haul overland movement of refined petroleum products. Therefore, the Pipeline Operations segment s most significant competitors for large volume shipments are other pipelines, some of which are owned or controlled by major integrated oil companies. Although it is unlikely that a pipeline system comparable in size and scope to the Pipeline Operations segment s pipeline systems will be built in the foreseeable future, new pipelines (including pipeline segments that connect with existing pipeline systems) could be built to effectively compete with the Pipeline Operations segment in particular locations.

The Pipeline Operations segment competes with marine transportation in some areas. Tankers and barges on the Great Lakes account for some of the volume to certain Michigan, Ohio and upstate New York locations during the approximately eight non-winter months of the year. Barges are presently a competitive factor for deliveries to the New York City area, the Pittsburgh area, Connecticut and locations on the Ohio River such as Mt. Vernon, Indiana and Cincinnati, Ohio and locations on the Mississippi River such as St. Louis, Missouri.

Trucks competitively deliver refined petroleum products in a number of areas that the Pipeline Operations segment serves. While their costs may not be competitive for longer hauls or large volume shipments, trucks compete effectively for smaller volumes in many local areas. The availability of truck transportation places a significant competitive constraint on the ability of the Pipeline Operations segment to increase its tariff rates.

Privately arranged exchanges of refined petroleum products between marketers in different locations are another form of competition. Generally, such exchanges reduce both parties costs by eliminating or reducing transportation charges. In addition, consolidation among refiners and marketers that has accelerated in recent years has altered distribution patterns, reducing demand for transportation services in some markets and increasing them in other markets.

The production and use of biofuels may be a competitive factor in that, to the extent the usage of biofuels increases, some alternative means of transport that compete with our pipelines may be able to provide transportation services for biofuels that our pipelines cannot because of safety or pipeline integrity issues. In particular, railroads competitively deliver biofuels to a number of areas and, therefore, are a significant competitor of pipelines with respect to biofuels. Biofuel usage may also create opportunities for additional pipeline transportation, if such biofuels can be transported on our pipeline, and additional blending opportunities within our Terminalling and Storage segment, although that potential cannot be quantified at present.

Distribution of refined petroleum products depends to a large extent upon the location and capacity of refineries. However, because the Pipeline Operations segment s business is largely driven by the consumption of fuel in its delivery areas and the Pipeline Operations pipelines have numerous source points, we do not believe that the expansion or shutdown of any particular refinery is likely, in most instances, to have a material effect on the business of the Pipeline Operations segment. As discussed in Item 1A. Risk Factors below, however, a significant decline in production at the ConocoPhillips Wood River refinery, Valero Paulsboro refinery or Husky Lima refinery could materially impact the business of the Pipeline Operations segment.

Many of the general competitive factors discussed above, such as demand for refined petroleum products and competitive threats from methods of transportation other than pipelines, also impacts our Terminalling and Storage segment. The Terminalling and Storage segment generally competes with other terminals in the same geographic market. Many competitive terminals are owned by major integrated oil companies. These major oil companies may have the opportunity for product exchanges that are not available to the Terminalling and Storage segment s terminals. While the Terminalling and Storage segment s terminal throughput fees are not regulated, they are subject to price competition from competitive terminals and alternate modes of transporting refined petroleum products to end users such as retail gas stations.

Natural Gas Storage Segment

The Natural Gas Storage segment competes with other storage providers, including local distribution companies (LDCs), utilities and affiliates of LDCs and other independent utilities in the northern California natural gas storage market. Certain major pipeline companies have existing storage facilities connected to their systems that compete with the Natural Gas Storage segment s facilities. Ongoing and proposed third-party construction of new capacity in northern California could have an adverse impact on the Natural Gas Storage segment s competitive position.

Energy Services Segment

The Energy Services segment competes with pipeline companies, the major integrated oil companies, their marketing affiliates and independent gatherers, investment banks that have established a trading platform, and brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources greater than the Energy Services segment, and control greater supplies of refined petroleum products.

Development and Logistics

The Development and Logistics segment competes with independent pipeline companies, engineering firms, major integrated oil companies and chemical companies to operate and maintain logistic assets for third-party owners. In addition, in many instances it is more cost-effective for certain companies to operate and maintain their own pipelines as opposed to contracting with the Development and Logistics segment to complete these tasks. Numerous engineering and construction firms compete with the Development and Logistics segment for construction management business.

Customers

For the years ended December 31, 2009 and 2008, no customer contributed more than 10% of our consolidated revenue. In 2007, Shell Oil Products U.S. (Shell) contributed 10% of our consolidated revenue. Approximately 3% of 2007 consolidated revenue was generated by Shell in the Pipeline Operations segment, and the remaining 7% of consolidated revenue generated by Shell was in the Terminalling and Storage segment.

Seasonality

The Pipeline Operations and Terminalling and Storage segments mix and volume of products transported and stored tends to vary seasonally. Declines in demand for heating oil during the summer months are, to a certain extent, offset by increased demand for gasoline and jet fuel. Overall, these segments have been only moderately seasonal, with somewhat lower than average volumes being transported and stored during March, April and May and somewhat higher than average volumes being transported and stored in November, December and January.

The Natural Gas Storage segment typically has two injection and two withdrawal seasons during the year. Our natural gas storage facility is normally at capacity prior to the summer cooling season and prior to the winter heating season. Since our customers pay a demand fee, they are generally incentivized to maximize their use of the storage facility throughout the year.

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The Energy Services segment s mix and volume of product sales tends to vary seasonally, with the fourth and first quarter volumes generally being higher than the second and third quarters, primarily due to the increased demand for home heating oil in the winter months.

Employees

Except as noted below, we are managed and operated by employees of Buckeye Pipe Line Services Company, a Pennsylvania corporation (Services Company), which is a consolidated affiliate of BGH, the owner of our general partner. At December 31, 2009, Services Company had approximately 846 full-time employees, 162 of whom were represented by two labor unions. Approximately 18 people are employed directly by Lodi Gas and 15 people are employed directly by a subsidiary of BPH. We reimburse Services Company for the cost of providing those employee services pursuant to a services agreement. We have never experienced any work stoppages or other significant labor problems.

Capital Expenditures

We make capital expenditures in order to maintain and enhance the safety and integrity of our pipelines, terminals, storage facilities and related assets, to expand the reach or capacity of those assets, to improve the efficiency of our operations and to pursue new business opportunities. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

During 2009, we spent approximately $87.3 million for capital expenditures, of which $23.5 million related to sustaining capital projects and $63.8 million related to expansion and cost reduction projects.

We expect to spend approximately $90.0 million to $110.0 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 $65.0 million to $75.0 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, the construction of a 4.4 mile pipeline in central Connecticut to connect our pipeline in Connecticut to a third-party electric generation plant currently under construction, various terminal expansions and upgrades and pipeline and terminal automation projects.

Regulation

General

We are subject to extensive laws and regulations as well as regulatory oversight by numerous federal, state and local departments and agencies, many of which are authorized by statute to issue rules and regulations binding on the pipeline industry, related businesses and individual participants. In some states, we are subject to the jurisdiction of public utility commissions, which have authority over, among other things, intrastate tariffs, the issuance of debt and equity securities, transfers of assets and safety. The failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on our operations increases our cost of doing business and, consequently, affects our profitability. However, except for certain exemptions that apply to smaller companies, we do not believe that we are affected in a significantly different manner by these laws and regulations than are our competitors.

Following is a discussion of certain laws and regulations affecting us. However, you should not rely on such discussion as an exhaustive review of all regulatory considerations affecting our operations.

Rate Regulation

Buckeye Pipe Line, Wood River, BPL Transportation and NORCO operate pipelines subject to the regulatory jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Interstate Commerce Act and the Department of Energy Organization Act. FERC regulations require that interstate oil pipeline rates be posted publicly and that these rates be just and reasonable and not unduly discriminatory. FERC regulations also enforce common carrier obligations and specify a uniform system of accounts, among certain other obligations.

The generic oil pipeline regulations issued under the Energy Policy Act of 1992 rely primarily on an index methodology that allows a pipeline to change its rates in accordance with an index (currently the change in the Producer Price Index (PPI) plus 1.3%) that FERC believes reflects cost changes appropriate for application to pipeline rates. Under FERC s rules, as one alternative to indexed rates, a pipeline is also allowed to charge market-based rates if the pipeline establishes that it does not possess significant market power in a particular market. The final rules became effective on January 1, 1995. FERC is expected to reexamine the manner in which the index is calculated in 2010 as part of its regular five-year review.

The tariff rates of Wood River, BPL Transportation and NORCO are governed by the generic FERC index methodology, and therefore are subject to change annually according to the index. If PPI + 1.3% is negative in a future period, then Wood River, BPL Transportation and NORCO could be required to reduce their rates if they exceed the new maximum allowable rate. For comparison, at December 31, 2009, the PPI + 1.3% for 2009 was estimated to be 1.24% based on preliminary data. Shippers may also file complaints against indexed rates as being unjust and unreasonable, subject to the FERC s standards.

Buckeye Pipe Line s rates are governed by an exception to the rules discussed above, pursuant to specific FERC authorization. Buckeye Pipe Line s market-based rate regulation program was initially approved by FERC in March 1991 and was subsequently extended in 1994. Under this program, in markets where Buckeye Pipe Line does not have significant market power, individual rate increases: (a) will not exceed a real (i.e., exclusive of inflation) increase of 15% over any two-year period, and (b) will be allowed to become effective without suspension or investigation if they do not exceed a trigger equal to the change in the Gross Domestic Product implicit price deflator since the date on which the individual rate was last increased, plus 2%. Individual rate decreases will be presumptively valid upon a showing that the proposed rate exceeds marginal costs. In markets where Buckeye Pipe Line was found to have significant market power and in certain markets where no market power finding was made: (i) individual rate increases cannot exceed the volume-weighted average rate increase in markets where Buckeye Pipe Line does not have significant market power since the date on which the individual rate was last increased, and (ii) any volume-weighted average rate decrease in markets where Buckeye Pipe Line does not have significant market power must be accompanied by a corresponding decrease in all of Buckeye Pipe Line s rates in markets where it does have significant market power. Shippers retain the right to file complaints or protests following notice of a rate increase, but are required to show that the proposed rates violate or have not been adequately justified under the market-based rate regulation program, that the proposed rates are unduly discriminatory, or that Buckeye Pipe Line has acquired significant market power in markets previously found to be competitive.

The Buckeye Pipe Line program was subject to review by FERC in 2000 when FERC reviewed the index selected in the generic oil pipeline regulations. FERC decided to continue the generic oil pipeline regulations with no material changes and did not modify or discontinue Buckeye Pipe Line s program. We cannot predict the impact that any change to Buckeye Pipe Line s rate program would have on Buckeye Pipe Line s operations. Independent of regulatory considerations, it is expected that tariff rates will continue to be constrained by competition and other market factors.

Laurel operates a pipeline in intrastate service across Pennsylvania, and its tariff rates are regulated by the Pennsylvania Public Utility Commission. Wood River operates a pipeline in intrastate service in Illinois, and tariff rates related to this pipeline are regulated by the Illinois Commerce Commission.

Lodi Gas owns and operates a natural gas storage facility in northern California under a Certificate of Public Convenience and Necessity originally granted by the California Public Utilities Commission (CPUC) in 2000 and expanded in 2006, 2008 and 2009. Under the Hinshaw exemption to the Natural Gas Act, Lodi Gas is not subject to FERC rate regulation, but is regulated by the CPUC and other state and local agencies in California. Consistent with California regulatory policy, however, Lodi Gas is authorized to charge market-based rates and is not otherwise subject to rate regulation.

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Environmental Regulation

We are subject to federal, state and local laws and regulations relating to the protection of the environment. Although we believe that our operations comply in all material respects with applicable environmental laws and regulations, risks of substantial liabilities are inherent in pipeline operations, and we cannot assure you that material environmental liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly rigorous environmental laws, regulations and enforcement policies, and claims for damages to property or injuries to persons resulting from our operations, could result in substantial costs and liabilities to us. See Legal Proceedings.

The Oil Pollution Act of 1990 (OPA) amended certain provisions of the federal Water Pollution Control Act of 1972, commonly referred to as the Clean Water Act (CWA), and other statutes, as they pertain to the prevention of and response to petroleum product spills into navigable waters. The OPA subjects owners of facilities to strict joint and several liability for all containment and clean-up costs and certain other damages arising from a spill. The CWA provides penalties for the discharge of petroleum products in reportable quantities and imposes substantial liability for the costs of removing a spill. State laws for the control of water pollution also provide varying civil and criminal penalties and liabilities in the case of releases of petroleum or its derivatives into surface waters or into the ground.

Contamination resulting from spills or releases of refined petroleum products sometimes occurs in the petroleum pipeline industry. Our pipelines cross numerous navigable rivers and streams. Although we believe that we comply in all material respects with the spill prevention, control and countermeasure requirements of federal laws, any spill or other release of petroleum products into navigable waters may result in material costs and liabilities to us.

The Resource Conservation and Recovery Act (RCRA), as amended, establishes a comprehensive program of regulation of hazardous wastes. Hazardous waste generators, transporters, and owners or operators of treatment, storage and disposal facilities must comply with regulations designed to ensure detailed tracking, handling and monitoring of these wastes. RCRA also regulates the disposal of certain non-hazardous wastes. As a result of these regulations, certain wastes typically generated by pipeline operations are considered hazardous wastes. Hazardous wastes are subject to more rigorous and costly disposal requirements than are non-hazardous wastes. Any changes in the regulations could have a material adverse effect on our maintenance capital expenditures and operating expenses.

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA), also known as Superfund, governs the release or threat of release of a hazardous substance. Releases of a hazardous substance, whether on or off-site, may subject the generator of that substance to joint and several liability under CERCLA for the costs of clean-up and other remedial action. Pipeline maintenance and other activities in the ordinary course of business generate hazardous substances. As a result, to the extent a hazardous substance generated by us or our predecessors may have been released or disposed of in the past, we may in the future be required to remediate contaminated property. Governmental authorities such as the Environmental Protection Agency (EPA), and in some instances third parties, are authorized under CERCLA to seek to recover remediation and other costs from responsible persons, without regard to fault or the legality of the original disposal. In addition to our potential liability as a generator of a hazardous substance, our property or right-of-way may be adjacent to or in the immediate vicinity of Superfund and other hazardous waste sites. Accordingly, we may be responsible under CERCLA for all or part of the costs required to cleanup such sites which could be material.

The Clean Air Act, amended by the Clean Air Act Amendments of 1990 (the Amendments), imposes controls on the emission of pollutants into the air. The Amendments required states to develop facility-wide permitting programs to comply with new federal programs. Existing operating and air-emission requirements like those currently imposed on us are being reviewed by appropriate state agencies in connection with the new facility-wide permitting program. It is possible that new or more stringent controls will be imposed on us through this program.

We are also subject to environmental laws and regulations adopted by the various states in which we operate. In certain instances, the regulatory standards adopted by the states are more stringent than applicable federal laws.

Pipeline and Terminal Maintenance and Safety Regulation

The pipelines we operate are subject to regulation by the U.S. Department of Transportation (DOT) and its agency, the Pipeline and Hazardous Materials Safety Administration (PHMSA), under the Hazardous Liquid Pipeline Safety Act of 1979 (HLPSA), which governs the design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA covers petroleum and petroleum products pipelines and requires any entity that owns or operates pipeline facilities to comply with applicable safety standards, to establish and maintain a plan of inspection and maintenance and to comply with such plans.

The Pipeline Safety Reauthorization Act of 1988 requires coordination of safety regulation between federal and state agencies, testing and certification of pipeline personnel, and authorization of safety-related feasibility studies. We have a drug and alcohol testing program that complies in all material respects with the regulations promulgated by the Office of Pipeline Safety and DOT.

HLPSA also requires, among other things, that the Secretary of Transportation consider the need for the protection of the environment in issuing federal safety standards for the transportation of hazardous liquids by pipeline. The legislation also requires the Secretary of Transportation to issue regulations concerning, among other things, the identification by pipeline operators of environmentally sensitive areas; the circumstances under which emergency flow restricting devices should be required on pipelines; training and qualification standards for personnel involved in maintenance and operation of pipelines; and the periodic integrity testing of pipelines in unusually sensitive and high-density population areas by internal inspection devices or by hydrostatic testing. Effective in August 1999, the DOT issued its Operator Qualification Rule, which required a written program by April 27, 2001, for ensuring operators are qualified to perform tasks covered by the pipeline safety rules. All persons performing covered tasks were required to be qualified under the program by October 28, 2002. We filed our written plan and have qualified our employees and contractors as required and requalified the employees under our plan again in 2005, and we have since implemented a formalized requalification program. On March 31, 2001, DOT s rule for Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators with 500 or more Miles of Pipeline) became effective. This rule sets forth regulations that require pipeline operators to assess, evaluate, repair and validate the integrity of hazardous liquid pipeline segments that, in the event of a leak or failure, could affect populated areas, areas unusually sensitive to environmental damage or commercially navigable waterways. Under the rule, pipeline operators were required to identify line segments which could impact high consequence areas by December 31, 2001. Pipeline operators were required to develop Baseline Assessment Plans for evaluating the integrity of each pipeline segment by March 31, 2002 and to complete an assessment of the highest risk 50% of line segments by September 30, 2004, with full assessment of the remaining 50% by March 31, 2008. Pipeline operators are now required to re-assess each affected segment in intervals not to exceed five years. We have implemented an Integrity Management Program in compliance with the requirements of this rule.

In December 2002, the Pipeline Safety Improvement Act of 2002 (PSIA) became effective. The PSIA imposes additional obligations on pipeline operators, increases penalties for statutory and regulatory violations, and includes provisions prohibiting employers from taking adverse employment action against pipeline employees and contractors who raise concerns about pipeline safety within the company or with government agencies or the press. Many of the provisions of the PSIA are subject to regulations to be issued by the DOT. The PSIA also requires public education programs for residents, public officials and emergency responders and a measurement system to ensure the effectiveness of the public education program. We implemented a public education program that complies with these requirements and the requirements of the American Petroleum Institute Recommended Practice 1162.

The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES Act), which became effective on December 24, 2006, among other things, reauthorized HLPSA, strengthened damage prevention measures designed to protect pipelines from excavation damage, removed the exemption from regulation of pipelines operating at less than 20% of maximum yield strength in rural areas, and required pipeline operators to manage human factors in pipeline control centers, including controller fatigue. While the PIPES Act imposed additional operating requirements on pipeline operators, we do not believe that the costs of compliance with the PIPES Act are material, because many of the new requirements are already satisfied by our existing programs.

Our natural gas storage operations are also subject to regulation by the DOT under the Natural Gas Pipeline Safety Act of 1968 (NGPSA) as subsequently amended, which required the Secretary of Transportation to implement regulations imposing safety and reporting obligations.

We believe that we currently comply in all material respects with HLPSA, the PSIA, the PIPES Act, the NGPSA and other pipeline safety laws and regulations. However, the industry, including us, will incur additional pipeline and tank integrity expenditures in the future, and we are likely to incur increased operating costs based on these and other government regulations.

We are also subject to the requirements of the Occupational Safety and Health Act (OSHA) and comparable state statutes. We believe that our operations comply in all material respects with OSHA requirements, including general industry standards, record-keeping and the training and monitoring of occupational exposures.

We cannot predict whether or in what form any new legislation or regulatory requirements might be enacted or adopted or the costs of compliance. In general, any such new regulations could increase operating costs and impose additional capital expenditure requirements, but we do not presently expect that such costs or capital expenditure requirements would have a material adverse effect on our results of operations or financial condition.

Tax Considerations for Unitholders

This section is a summary of material tax considerations that may be relevant to our Unitholders. It is based upon the Internal Revenue Code of 1986, as amended (the Code), regulations promulgated thereunder and current administrative rulings and court decisions, all of which are subject to change. Subsequent changes in such authorities may cause the tax consequences to vary substantially from the consequences described below.

No attempt has been made in the following discussion to comment on all federal income tax matters affecting us or our Unitholders. Moreover, the discussion focuses on Unitholders who are individuals and who are citizens or residents of the United States and has only limited application to corporations, estates, trusts, non-resident aliens or other Unitholders subject to specialized tax treatment, such as tax-exempt institutions, foreign persons, individual retirement accounts (IRAs), REITs or mutual funds.

UNITHOLDERS ARE URGED TO CONSULT, AND SHOULD DEPEND ON, THEIR OWN TAX ADVISORS IN ANALYZING THE FEDERAL, STATE, LOCAL AND FOREIGN TAX CONSEQUENCES TO THEM OF THE OWNERSHIP OR DISPOSITION OF LP UNITS.

Characterization of Buckeye for Tax Purposes

A partnership is not a taxable entity and incurs no federal income tax liability. Instead, partners are required to take into account their respective allocable shares of our items of income, gain, loss and deduction in computing their federal income tax liability, regardless of whether cash distributions are made. Distributions of cash by a partnership to a partner are generally not taxable unless the amount of cash distributed to a partner is in excess of the partner s tax basis in his partnership interest. Allocable shares of partnership tax items are generally determined by a partnership agreement. However, the Internal Revenue Service (IRS) may disregard such an agreement in certain instances and re-determine the tax consequences of partnership operations to the partners.

Section 7704 of the Code provides that publicly traded partnerships (such as us) will, as a general rule, be taxed as corporations. However, an exception to this rule exists with respect to any publicly traded partnerships of which 90% or more of its gross income for each taxable year consists of qualifying income (the Qualifying Income Exception). Qualifying income includes interest (other than interest generated by a financial or insurance business), dividends, real property rents, gains from the sale or disposition of real property, and, most importantly for Unitholders, income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil or products thereof), or the marketing of any mineral or natural resource (including fertilizer, geothermal energy and timber) . . . , or the transportation or storage of [ethanol]..., and gain from the sale or disposition of capital assets that produce such income.

We are engaged primarily in the refined petroleum products transportation, storage and marketing businesses and natural gas storage business. We believe that at least 90% or more of our current gross income constitutes, and has constituted, qualifying income and, accordingly, that we will continue to be classified as a partnership and not as a corporation for federal income tax purposes.

If we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery, we will be treated as if we had transferred all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed that stock to our Unitholders in liquidation of their interests in us. This contribution and liquidation should be tax-free to Unitholders and us so long as we, at that time, do not have liabilities in excess of the tax basis of our assets. Thereafter, we would be treated as a corporation for federal income tax purposes.

If we were taxed as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our items of income, gain, loss and deduction would be reflected only on our tax return rather than being passed through to our Unitholders, and our net income would be taxed to us at corporate rates. If we were taxed as a corporation, losses we recognized would not flow through to our Unitholders. In addition, any distribution we made to a Unitholder would be treated as either taxable dividend income, to the extent of current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the Unitholder s tax basis in his units, or taxable capital gain, after the Unitholder s tax basis in his units is reduced to zero. Accordingly, our taxation as a corporation would result in a material reduction in a Unitholder s cash flow and after-tax return and thus would likely result in a substantial reduction in the value of the LP Units.

Allocation of Partnership Income, Gain, Loss and Deduction

Our items of income, gain, loss and deduction will generally be allocated among Buckeye GP and our Unitholders in accordance with their respective percentage interests in us.

Certain items of our income, gain, loss or deduction will be allocated as required or permitted by Section 704(c) of the Code to account for the difference between the tax basis and fair market value of property contributed to us. Allocations will also be made to account for the difference between the fair market value of our assets and our tax basis at the time of any offering.

In addition, certain items of recapture income that we recognize on the sale of any of our assets will be allocated to the extent provided in regulations and our partnership agreement, which generally require such depreciation recapture to be allocated to the partner who (or whose predecessor in interest) was allocated the deduction giving rise to the treatment of such gain as recapture income.

Treatment of Partnership Distributions

Our distributions to a Unitholder generally will not be taxable for federal income tax purposes to the extent of the Unitholder s tax basis in our LP Units immediately before the distribution. Distributions in excess of a Unitholder s tax basis generally will be considered to be a gain from the sale or exchange of the LP Units, taxable in accordance with the rules described under Disposition of LP Units, set forth below. Any reduction in a Unitholder s share of our liabilities for which no partner, including Buckeye GP, bears the economic risk of loss (nonrecourse liabilities) will be treated as a distribution of cash to that Unitholder.

A decrease in a Unitholder s percentage interest in us because of our issuance of additional LP Units will decrease such Unitholder s share of our nonrecourse liabilities, and thus will result in a corresponding deemed distribution of cash. This deemed distribution may constitute a non-pro rata distribution. A non-pro rata distribution of money or property may result in ordinary income to a Unitholder if such distribution reduces the Unitholder s share of our unrealized receivables, including depreciation recapture or substantially appreciated inventory items, both as defined in Section 751 of the Code (collectively, Section 751 Assets).

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Basis of LP Units

A Unitholder will have an initial tax basis for its LP Units equal to the amount paid for the LP Units plus its share of our liabilities. A Unitholder s tax basis will be increased by his share of our income and by any increase in his share of our liabilities. A Unitholder s tax basis will be decreased, but not below zero, by his share of our distributions, by his share of our losses, by any decrease in his share of our liabilities and by his share of our expenditures that are not deductible in computing our taxable income and are not required to be capitalized.

Loss Limitations

The deduction by a Unitholder of that Unitholder s allocable share of our losses will be limited to the amount of that Unitholder s tax basis in his or her LP Units and, in the case of an individual Unitholder or a corporate Unitholder who is subject to the at risk rules (generally, certain closely-held corporations), to the amount for which the Unitholder is considered to be at risk with respect to our activities, if that is less than the Unitholder s tax basis. A Unitholder must recapture losses deducted in previous years to the extent that distributions cause the Unitholder s at risk amount to be less than zero at the end of any taxable year. Losses disallowed to a Unitholder or recaptured as a result of these limitations will carry forward and will be allowable as a deduction to the extent that his at-risk amount is subsequently increased, provided such losses do not exceed such Unitholder s tax basis in his LP Units. Upon the taxable disposition of an LP Unit, any gain recognized by a Unitholder can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation.

In general, a Unitholder will be at risk to the extent of the Unitholder s tax basis in the Unitholder s LP Units, excluding any portion of that basis attributable to the Unitholder s share of our nonrecourse liabilities, reduced by (i) any portion of that basis representing amounts otherwise protected against loss because of a guarantee, stop loss agreement or other similar arrangement and (ii) any amount of money the Unitholder borrows to acquire or hold the Unitholder s LP Units if the lender of such borrowed funds owns an interest in us, is related to such a person or can look only to LP Units for repayment. A Unitholder s at risk amount will increase or decrease as the tax basis of the Unitholder s LP Units increases or decreases, other than tax basis increases or decreases attributable to increases or decreases in the Unitholder s share of our nonrecourse liabilities.

The passive loss limitations generally provide that individuals, estates, trusts, certain closely-held corporations and personal service corporations can deduct losses from passive activities, which include any trade or business activity in which the taxpayer does not materially participate, only to the extent of the taxpayer s income from those passive activities. Moreover, the passive loss limitations are applied separately with respect to each publicly traded partnership. Consequently, any passive losses that we generate will only be available to Unitholders who are subject to the passive loss rules to offset future passive income that we generate and, in particular, will not be available to offset income from other passive activities, investments or salary. Passive losses that are not deductible because they exceed a Unitholder s share of income may be deducted in full when the Unitholder disposes of the Unitholder s entire investment in us in a fully taxable transaction to an unrelated party. The passive activity loss rules are applied after other applicable limitations on deductions such as the at-risk rules and the basis limitation.

Deductibility of Interest Expense

The Code generally provides that investment interest expense is deductible only to the extent of a non-corporate taxpayer s net investment income. In general, net investment income for purposes of this limitation includes gross income from property held for investment, gain attributable to the disposition of property held for investment (except for net capital gains for which the taxpayer has elected to be taxed at special capital gains rates) and portfolio income (determined pursuant to the passive loss rules as income not derived from a trade or business) reduced by certain expenses (other than interest) which are directly connected with the production of such income. Property that generates passive losses under the passive loss rules is not generally treated as property held for investment. However, the IRS has issued a Notice which provides that net income from a publicly traded partnership (not otherwise treated as a corporation) may be included in net investment income for purposes of the limitation on the deductibility of investment interest. Furthermore, a Unitholder s investment income attributable to its LP Units will also include its allocable share of our portfolio income. A Unitholder s investment interest expense will include its allocable share of our interest expense attributable to portfolio investments.

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Withholding

If we were required or elected under applicable law to pay any federal, state or local income tax on behalf of any Unitholder, we are authorized to pay those taxes from our funds. Such payment, if made, will be treated as a distribution of cash to the Unitholder on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, we are authorized to treat the payment as a distribution to a current Unitholder.

Alternative Minimum Tax

Each Unitholder will be required to take into account his share of items of income, gain, loss or deduction for purposes of the alternative minimum tax. A portion of depreciation deductions may be treated as an item of tax preference for this purpose. A Unitholder s alternative minimum taxable income derived from us may be higher than his share of our net income because we may use accelerated methods of depreciation for federal income tax purposes. Prospective Unitholders should consult their tax advisors as to the impact of an investment in LP Units on their liability for the alternative minimum tax.

Section 754 Election

We have made the election permitted by Section 754 of the Code, which effectively permits us to adjust the tax basis of our assets to each purchaser of our LP Units from another Unitholder pursuant to Section 743(b) of the Code to reflect the purchaser s purchase price. The Section 743(b) adjustment is intended to provide a purchaser with the equivalent of an adjusted tax basis in the purchaser s share of our assets equal to the value of such share that is indicated by the amount that the purchaser paid for the LP Units.

A Section 754 election is advantageous if the transferee s tax basis in the transferee s LP Units is higher than such LP Units share of the aggregate tax basis of our assets immediately prior to the transfer because the transferee would have, as a result of the election, a higher tax basis in the transferee s share of our assets. Conversely, a Section 754 election is disadvantageous if the transferee s tax basis in the transferee s LP Units is lower than such LP Units share of the aggregate tax basis of our assets immediately prior to the transfer. The Section 754 election is irrevocable without the consent of the IRS.

We intend to compute the effect of the Section 743(b) adjustment so as to preserve the ability to determine the tax attributes of an LP Unit from its date of purchase and the amount paid therefore. In that regard, we have adopted depreciation and amortization conventions that may not conform with all aspects of applicable Treasury Regulations, though we believe that they do conform to Section 743(b) of the Code.

The calculations involved in the Section 754 election are complex and are made by us on the basis of certain assumptions as to the value of assets and other matters. There is no assurance that the determinations that we made will prevail if challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether.

Tax Treatment of Operations

We use the adjusted tax basis of our various assets for purposes of computing depreciation and cost recovery deductions and gain or loss on any disposition of such assets. If we dispose of depreciable property, all or a portion of any gain may be subject to the recapture rules and taxed as ordinary income rather than capital gain.

The costs incurred in promoting the issuance of LP Units (i.e., syndication expenses) must be capitalized and cannot be deducted by us currently, ratably or upon our termination. Uncertainties exist regarding the classification of costs as organization expenses, which may be amortized, and as syndication expenses, which may not be amortized.

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Valuation of Partnership Properties

The federal income tax consequences of the ownership and disposition of LP Units will depend in part on our estimates of the fair market values and our determination of the adjusted tax basis of our assets. We will make many of the fair market value estimates ourselves. These estimates and determinations are subject to challenge and will not be binding on the IRS or the courts. If such estimates or determinations of basis are subsequently found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by Unitholders might change, and Unitholders might be required to adjust their tax liability for prior years.

Disposition of LP Units

A Unitholder will recognize gain or loss on a sale of LP Units equal to the difference between the amount realized and the Unitholder s tax basis in the LP Units sold. A Unitholder s amount realized is measured by the sum of the cash and the fair market value of other property received plus his share of our liabilities. Because the amount realized includes a Unitholder s share of our liabilities, the gain recognized on the sale of LP Units could result in a tax liability in excess of any cash received from such sale.

Gain or loss recognized by a Unitholder, other than a dealer in LP Units, on the sale or exchange of an LP Unit will generally be a capital gain or loss. Capital gain recognized on the sale of LP Units by an individual Unitholder held for more than one year will generally be taxed at a maximum rate of 15% (such rate to be increased to 20% for taxable years beginning after December 31, 2010). A portion of this gain or loss (which could be substantial), however, will be separately computed and will be classified as ordinary income or loss under Section 751 of the Code to the extent attributable to assets giving rise to depreciation recapture or other unrealized receivables or to inventory items we own. In general, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 35% (such rate to be increased to 39.6% for taxable years beginning after December 31, 2010). Ordinary income attributable to Section 751 may exceed net taxable gain realized upon the sale of the LP Units and will be recognized even if there is a net taxable loss realized on the sale of the LP Units. Thus, a Unitholder may recognize both ordinary income and a capital loss upon a disposition of LP Units. Net capital loss may offset no more than $3,000 ($1,500 in the case of a married individual filing a separate return) of ordinary income in the case of individuals and may only be used to offset capital gain in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis. Upon a sale or other disposition of less than all of such interests, a portion of that tax basis must be allocated to the interests sold based upon relative fair market values. On the other hand, a selling partner who can identify partnership interests transferred with an ascertainable holding period may elect to use the actual holding period of our interests transferred. A partner electing to use the actual holding period of partnership interests transferred must consistently use that identification method for all later sales or exchanges of partnership interests.

Specific provisions of the Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an appreciated partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Notification Requirements

A Unitholder who sells or exchanges LP Units is required to notify us in writing of that sale or exchange within 30 days after the sale or exchange and in any event by no later than January 15 of the year following the calendar year in which the sale or exchange occurred. We are required to notify the IRS of that transaction and to furnish certain information to the transferor and transferee. However, these reporting requirements do not apply with respect to a sale by an individual who is a citizen of the United States and who effects the sale or exchange through a broker. Failure to satisfy these reporting obligations may lead to the imposition of substantial penalties by the IRS.

Constructive Termination

We will be considered terminated if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of measuring whether the 50% threshold is reached, multiple sales of the same interest are counted only once. Any such termination would result in the closing of our taxable year for all Unitholders. In the case of a Unitholder reporting on a taxable year that does not end with our taxable year, the closing of the taxable year may result in more than 12 months of taxable income or loss being includable in that Unitholder s taxable income for the year of termination. New tax elections required to be made by us, including a new election under Section 754 of the Code, must be made subsequent to a termination and a termination could result in a deferral of deductions for depreciation. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted prior to the termination. The IRS has announced in a news release, Industry Resolution Program Issue IR-2008-110, that it plans to issue guidance regarding the treatment of constructive terminations of publicly traded partnerships such as us. Any such guidance may change the application of the rules discussed above and may affect the tax treatment of a Unitholder. The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if the taxpayer requests relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

Unrelated Business Taxable Income

Certain entities otherwise exempt from federal income taxes (such as individual retirement accounts, pension plans and charitable organizations) are nevertheless subject to federal income tax on net unrelated business taxable income and each such entity must file a tax return for each year in which it has more than $1,000 of gross income from unrelated business activities. We believe that substantially all of our gross income will be treated as derived from an unrelated trade or business and taxable to such entities. The tax-exempt entity s share of our deductions directly connected with carrying on such unrelated trade or business are allowed in computing the entity s taxable unrelated business income. **ACCORDINGLY, TAX-EXEMPT ENTITIES, SUCH AS INDIVIDUAL RETIREMENT ACCOUNTS, PENSION PLANS AND CHARITABLE TRUSTS, ARE ENCOURAGED TO CONSULT THEIR PROFESSIONAL TAX ADVISORS REGARDING THE TAX IMPLICATIONS OF THEIR OWNERSHIP OF LP UNITS.**

Foreign Unitholders

Non-resident aliens and foreign corporations, trusts or estates which hold LP Units will be considered to be engaged in business in the United States on account of ownership of LP Units. As a consequence, they will be required to file U.S. federal tax returns in respect of their share of our income, gain, loss or deduction and pay U.S. federal income tax at regular rates on any net income or gain. Generally, a partnership is required to pay a withholding tax on the portion of the partnership s income which is effectively connected with the conduct of a United States trade or business and which is allocable to the foreign partners, regardless of whether any actual distributions have been made to such partners. However, under rules applicable to publicly traded partnerships, taxes may be withheld at the highest marginal rate applicable to individuals on actual cash distributions made to foreign Unitholders. Each foreign Unitholder must obtain a taxpayer identification number from the IRS and submit that number to the transfer agent of the publicly traded partnership on a Form W-8BEN or applicable substitute form to obtain credit for these withholding taxes.

Because a foreign corporation that owns LP Units will be treated as engaged in a United States trade or business, such a corporation will also be subject to United States branch profits tax at a rate of 30% (or any

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applicable lower treaty rate) of the portion of any reduction in the foreign corporation s U.S. net equity, which is the result of our activities. In addition, such Unitholder is subject to special information reporting requirements under Section 6038C of the Code.

A foreign Unitholder who sells or otherwise disposes of an LP Unit will be subject to U.S. federal income tax on gain realized from the sale or disposition of that LP Unit to the extent the gain is effectively connected with a U.S. trade or business of the foreign Unitholder. Under a ruling published by the IRS interpreting the scope of effectively connected income, a foreign Unitholder would be considered to be engaged in a trade or business in the U.S. by virtue of our U.S. activities, and part or all of that Unitholder s gain would be effectively connected with that Unitholder s indirect U.S. trade or business. Moreover, under the Foreign Investment in Real Property Tax Act, a foreign Unitholder generally will be subject to U.S. federal income tax upon the sale or disposition of an LP Unit if (i) he owned (directly or constructively applying certain attribution rules) more than 5% of our LP Units at any time during the five-year period ending on the date of such disposition and (ii) 50% or more of the fair market value of all of our assets consisted of U.S. real property interests at any time during the shorter of the period during which such Unitholder held the LP Units or the 5-year period ending on the date of disposition. Currently, more than 50% of our assets consist of U.S. real property interests, and we do not expect that to change in the foreseeable future. Therefore, foreign Unitholders may be subject to federal income tax on gain from the sale or disposition of their LP Units.

Regulated Investment Companies

A regulated investment company, or mutual fund, is required to derive 90% or more of its gross income from specific sources including interest, dividends and gains from the sale of stocks or securities, foreign currency or specified related sources, and net income derived from the ownership of an interest in a qualified publicly traded partnership. We expect that we will meet the definition of a qualified publicly traded partnership.

State Tax Treatment

During 2009, we owned property or conducted business in the states of California, Colorado, Connecticut, Delaware, Florida, Illinois, Indiana, Kansas, Louisiana, Maryland, Massachusetts, Michigan, Missouri, Nevada, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Texas, Virginia, West Virginia and Wisconsin. A Unitholder will likely be required to file state income tax returns and to pay applicable state income taxes in many of these states and may be subject to penalties for failure to comply with such requirements. Some of the states have proposed that we withhold a percentage of income attributable to our operations within the state for Unitholders who are non-residents of the state. In the event that amounts are required to be withheld (which may be greater or less than a particular Unitholder s income tax liability to the state), such withholding would generally not relieve the non-resident Unitholder from the obligation to file a state income tax return.

Certain Tax Consequences to Unitholders

It is the responsibility of each Unitholder to investigate the legal and tax consequences, under the laws of pertinent jurisdictions, of his investment in us. Accordingly, each Unitholder is urged to consult, and depend upon, his tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each Unitholder to file all state, local and foreign, as well as United States federal tax returns, that may be required of him.

Available Information

We file annual, quarterly and current reports and other documents with the SEC under the Securities Exchange Act of 1934 (the Exchange Act). The public can obtain any documents that we file with the SEC at *www.sec.gov*. We also make available free of charge our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after filing such materials with, or furnishing such materials to, the SEC, on or through our Internet website, *www.buckeye.com*. We are not including the information contained on our website as a part of, or incorporating it by reference into, this Report.

You can also find information about us at the offices of the NYSE, 20 Broad Street, New York, New York 10005 or at the NYSE s Internet website, *www.nyse.com*.

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

There are many factors that may affect us and our investments. Security holders and potential investors in our securities should carefully consider the risk factors set forth below, as well as the discussion of other factors that could affect us or our investments included elsewhere in this Report. If one or more of these risks were to materialize, our business, financial position or results of operations could be materially and adversely affected. We are identifying these risk factors as important risk 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.

Risks Inherent in our Business

Changes in petroleum demand and distribution may adversely affect our business. In addition, the current economic downturn could result in lower demand for a sustained period of time.

Demand for the services we provide depends upon the demand for refined petroleum products in the regions we serve and the supply of refined petroleum products in the regions connected to our pipelines. Prevailing economic conditions, refined petroleum product price levels and weather affect the demand for refined petroleum products. Changes in transportation and travel patterns in the areas served by our pipelines also affect the demand for refined petroleum products because a substantial portion of the refined petroleum products transported by our pipelines and throughput at our terminals is ultimately used as fuel for motor vehicles and aircraft. If these factors result in a decline in demand for refined petroleum products, our business would be particularly susceptible to adverse effects because we operate without the benefit of either exclusive franchises from government entities or long-term contracts.

In addition, in December 2007, Congress enacted the Energy Independence and Security Act of 2007, which, among other provisions, mandated annually increasing levels for the use of renewable fuels such as ethanol, which commenced in 2008 and escalates for 15 years, as well as increasing energy efficiency goals, including higher fuel economy standards for motor vehicles, among other steps. These statutory mandates or other similar renewable fuel or energy efficiency statutory mandates enacted by states may have the impact over time of reducing the demand for refined petroleum products in certain markets, particularly with respect to gasoline. Other legislative changes may similarly alter the expected demand and supply projections for refined petroleum products in ways that cannot be predicted.

Energy conservation, changing sources of supply, structural changes in the oil industry and new energy technologies also could adversely affect our business. We cannot predict or control the effect of these factors on us.

Economic conditions worldwide have from time to time contributed to slowdowns in the oil and gas industry, as well as in the specific segments and markets in which we operate, resulting in reduced supply or demand and increased price competition for our products and services. In addition, economic conditions could result in a loss of customers in our operating segments because their access to the capital necessary to purchase services we provide is limited. Our operating results may also be affected by uncertain or changing economic conditions in certain regions, including the challenges that are currently affecting economic conditions in the entire United States. If global economic and market conditions (including volatility in commodity markets) or economic conditions in the United States remain uncertain or persist, spread or deteriorate further, we may experience material impacts on our business, financial condition, results of operations or cash flows.

Competition could adversely affect our operating results.

Generally, pipelines are the lowest cost method for long-haul overland movement of refined petroleum products. Therefore, our most significant competitors for large volume shipments are other existing pipelines, some of which are owned or controlled by major integrated oil companies. In addition, new pipelines (including pipeline segments that connect with existing pipeline systems) could be built to effectively compete with us in particular locations.

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We compete with marine transportation in some areas. Tankers and barges on the Great Lakes account for some of the volume to certain Michigan, Ohio and upstate New York locations during the approximately eight non-winter months of the year. Barges are presently a competitive factor for deliveries to the New York City area, the Pittsburgh area, Connecticut and locations on the Ohio River such as Mt. Vernon, Indiana and Cincinnati, Ohio and locations on the Mississippi River such as St. Louis, Missouri.

Trucks competitively deliver refined petroleum products in a number of areas that we serve. While their costs may not be competitive for longer hauls or large volume shipments, trucks compete effectively for incremental and marginal volumes in many areas that we serve. The availability of truck transportation places a significant competitive constraint on our ability to increase our tariff rates.

Privately arranged exchanges of refined petroleum products between marketers in different locations are another form of competition. Generally, these exchanges reduce both parties costs by eliminating or reducing transportation charges. In addition, consolidation among refiners and marketers that has accelerated in recent years has altered distribution patterns, reducing demand for transportation services in some markets and increasing them in other markets.

Additionally, our Natural Gas Storage segment competes primarily with other storage facilities and pipelines in the storage of natural gas. Some of our competitors may have greater financial resources. Some of these competitors may expand or construct transportation and storage systems that would create additional competition for the services we provide to our customers. Increased competition could reduce the volumes of natural gas stored by us and could adversely affect our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows.

Finally, our Energy Services segment buys and sells refined petroleum products in connection with its marketing activities, and must compete with the major integrated oil companies, their marketing affiliates, and independent brokers and marketers of widely varying sizes, financial resources and experience. Some of these companies have superior access to capital resources, which could affect our ability to effectively compete with them.

All of these competitive pressures could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Mergers among our customers and competitors could result in lower volumes being shipped on our pipelines and stored in our terminals, thereby reducing the amount of cash we generate.

Mergers between existing customers could provide strong economic incentives for the combined entities to utilize their existing pipeline and terminal systems instead of ours. As a result, we could lose some or all of the volumes and associated revenues from these customers and we could experience difficulty in replacing those lost volumes and revenues. Because most of our operating costs are fixed, a reduction in volumes would result in not only a reduction of revenues, but also a decline in net income and cash flow of a similar magnitude, which would reduce our ability to meet our financial obligations and pay cash distributions.

We are a holding company and depend entirely on our Operating Subsidiaries distributions to service our debt obligations and pay cash distributions to our Unitholders.

We are a holding company with no material operations. If we do not receive cash distributions from our Operating Subsidiaries, we will not be able to meet our debt service obligations or to make cash distributions to our Unitholders. Among other things, this would adversely affect the market price of our LP Units. We are currently bound by the terms of the Credit Facility which prohibits us from making distributions to our Unitholders if a default under the Credit Facility exists at the time of the distribution or would result from the distribution. Our Operating Subsidiaries may from time to time incur additional indebtedness under agreements that contain restrictions which could further limit each Operating Subsidiary s ability to make distributions to us.

We may incur liabilities from assets we have acquired.

Some of the assets we have acquired have been used for many years to distribute, store or transport petroleum products. Releases from terminals or along pipeline rights-of-way may have occurred prior to our acquisition. In addition, releases may have occurred in the past that have not yet been discovered, which could require costly future remediation. If a significant release or event occurred in the past and we are responsible for all or a significant portion of the liability associated with such release or event, it could adversely affect our business, financial position, results of operations and cash flows.

A significant decline in production at certain refineries served by certain of our pipelines and terminals could materially reduce the volume of refined petroleum products we transport and adversely impact our operating results.

A refinery that our pipelines and terminals service could partially or completely shut down its operations, temporarily or permanently, due to factors such as unscheduled maintenance, catastrophes, labor difficulties, environmental proceedings or other litigation, loss of significant downstream customers; or legislation or regulation that adversely impacts the economics of refinery operations. For example, a significant decline in production at the ConocoPhillips Wood River refinery, Valero Paulsboro refinery or Husky Lima refinery could negatively impact the financial performance of such assets and adversely affect our business, financial position, results of operations or cash flows.

Potential future acquisitions and expansions, if any, may affect our business by substantially increasing the level of our indebtedness and contingent liabilities and increasing the risks of our being unable to effectively integrate these new operations.

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing assets and businesses. Acquisitions may require substantial capital or the incurrence of substantial indebtedness. If we consummate any future acquisitions, our capitalization and results of operations may change significantly.

Acquisitions and business expansions involve numerous risks, including difficulties in the assimilation of the assets and operations of the acquired businesses, inefficiencies and difficulties that arise because of unfamiliarity with new assets and the businesses associated with them and new geographic areas and the diversion of management s attention from other business concerns. Further, we may experience unanticipated delays in realizing the benefits of an acquisition or we may be unable to integrate certain assets we acquire as part of a larger acquisition to the extent such assets relate to a business for which we have no or limited experience. Following an acquisition, we may discover previously unknown liabilities associated with the acquired business for which we have no recourse under applicable indemnification provisions.

Debt securities we issue are, and will continue to be, junior to claims of our Operating Subsidiaries creditors.

Our outstanding debt securities are structurally subordinated to the claims of our Operating Subsidiaries creditors. In addition, any debt securities we issue in the future will likewise be subordinated in the same manner. Holders of the debt securities will not be creditors of our Operating Subsidiaries. Our claim to the assets of our Operating Subsidiaries derives from our own ownership interests in those Operating Subsidiaries. Claims of our Operating Subsidiaries creditors will generally have priority as to the assets of our Operating Subsidiaries over our own ownership interests and will therefore have priority over the holders of our debt, including our debt securities.

Our rate structures are subject to regulation and change by the FERC.

Buckeye Pipe Line, Wood River, BPL Transportation and NORCO are interstate common carriers regulated by the FERC under the Interstate Commerce Act and the Department of Energy Organization Act. The FERC s primary ratemaking methodology is price indexing. In the alternative, a pipeline is allowed to charge market-based rates if the pipeline establishes that it does not possess significant market power in a particular market.

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The indexing methodology is used to establish rates on the pipelines owned by Wood River, BPL Transportation and NORCO. The indexing method presently allows a pipeline to increase its rates by a percentage equal to the change in the PPI for finished goods plus 1.3%. If the change in PPI plus 1.3% were to be negative, and it is anticipated that this will occur in 2010, we would be required to reduce the rates charged by Wood River, BPL Transportation and NORCO if they exceed the new maximum allowable rate. FERC is expected to reexamine the index in 2010, and it may change the manner in which it calculates the index. In addition, changes in the PPI might not fully reflect actual increases in the costs associated with these pipelines, thus hampering our ability to recover our costs. Shippers may also file complaints against indexed rates as being unjust and unreasonable, subject to the FERC s cost-of-service standards.

Buckeye Pipe Line presently is authorized to charge rates set by market forces, subject to limitations, rather than by reference to costs historically incurred by the pipeline, in 15 regions and metropolitan areas. The Buckeye Pipe Line program is an exception to the generic oil pipeline regulations the FERC issued under the Energy Policy Act of 1992. The generic rules rely primarily on the index methodology described above.

The Buckeye Pipe Line rate program was reevaluated by the FERC in July 2000, and was allowed to continue with no material changes. We cannot predict the impact, if any, that a change in the FERC s method of regulating Buckeye Pipe Line would have on our business, financial condition, results of operations or cash flows.

Climate change legislation or regulations restricting emissions of greenhouse gases or setting fuel economy or air quality standards could result in increased operating costs or reduced demand for the refined petroleum products, natural gas and other hydrocarbon products that we transport, store or otherwise handle in connection with our business.

On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases endanger human health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth s atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act (CAA). In late September 2009, the EPA had proposed two sets of CAA regulations in anticipation of finalizing its endangerment findings that would require a reduction in emissions of greenhouse gases from motor vehicles and, also, could trigger permit review for greenhouse gas emissions from certain stationary sources. In addition, on September 22, 2009, the EPA issued a final CAA rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. These regulations will require reporting for some of our facilities, and additional EPA regulations that are expected to be adopted in 2010 will require certain of our other facilities to report their greenhouse gas emissions, possibly beginning in 2012 for emissions occurring in 2011. The adoption and implementation of any CAA regulations limiting emissions of greenhouse gases from our equipment and operations or any future laws or regulations that may be adopted to address greenhouse gas emissions could require us to incur costs to reduce emissions of greenhouse gases associated with our operations. The effect on our operations could include increased costs to operate and maintain our facilities, measure and report our emissions, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates we charge, such recovery of costs is uncertain and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC and the provisions of any final regulations. In addition, laws or regulations regarding fuel economy, air quality or greenhouse gas emissions could include efficiency requirements or other methods of curbing carbon emissions that could adversely affect demand for the refined petroleum products, natural gas and other hydrocarbon products that we transport, store or otherwise handle in connection with our business. A significant decrease in demand for petroleum products would have a material adverse effect on our business, financial condition, results of operations or cash flows.

Environmental regulation may impose significant costs and liabilities on us.

We are subject to federal, state and local laws and regulations relating to the protection of the environment. Risks of substantial environmental liabilities are inherent in our operations, and we cannot assure you that we will not incur material environmental liabilities. Additionally, our costs could increase significantly, and we could face substantial liabilities, if, among other developments:

- environmental laws, regulations and enforcement policies become more rigorous; or
- claims for property damage or personal injury resulting from our operations are filed.

Existing or future state or federal government regulations relating to certain chemicals or additives in gasoline or diesel fuel could require capital expenditures or result in lower pipeline volumes and thereby adversely affect our results of operations and cash flows.

Changes made to governmental regulations governing the components of refined petroleum products may necessitate changes to our pipelines and terminals which may require significant capital expenditures or result in lower pipeline volumes. For instance, the increasing use of ethanol as a fuel additive, which is blended with gasoline at product terminals, may lead to reduced pipeline volumes and revenue which may not be totally offset by increased terminal blending fees we may receive at our terminals.

DOT regulations may impose significant costs and liabilities on us.

Our pipeline operations and natural gas storage operations are subject to regulation by the DOT. These regulations require, among other things, that pipeline operators engage in a regular program of pipeline integrity testing to assess, evaluate, repair and validate the integrity of their pipelines, which, in the event of a leak or failure, could affect populated areas, unusually sensitive environmental areas or commercially navigable waterways. In response to these regulations, we conduct pipeline integrity tests on an ongoing and regular basis. Depending on the results of these integrity tests, we could incur significant and unexpected capital and operating expenditures, not accounted for in anticipated capital or operating budgets, in order to repair such pipelines to ensure their continued safe and reliable operation.

Our business is exposed to customer credit risk, against which we may not be able to fully protect.

Our businesses are subject to the risks of nonpayment and nonperformance by our customers. We manage our exposure to credit risk through credit analysis and monitoring procedures, and sometimes use letters of credit, prepayments and guarantees. However, these procedures and policies cannot fully eliminate customer credit risk, and to the extent our policies and procedures prove to be inadequate, it could negatively affect our financial condition and results of operations. In addition, some of our customers, counterparties and suppliers may be highly leveraged and subject to their own operating and regulatory risks and, even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with such parties. Volatility in commodity prices might have an impact on many of our customers, which in turn could have a negative impact on their ability to meet their obligations to us.

The marketing business in our Energy Services segment enters into sales contracts pursuant to which customers agree to buy refined petroleum products from us at a fixed-price on a future date. If our customers have not hedged their exposure to reductions in refined petroleum product prices and there is a price drop, then they could have a significant loss upon settlement of their fixed-price sales contracts with us, which could increase the risk of their nonpayment or nonperformance. In addition, we generally have entered into futures contracts to hedge our exposure under these fixed-price sales contracts to increases in refined petroleum product prices. If price levels are lower at settlement than when we entered into these futures contracts, then we will be required to make payments upon the settlement thereof. Ordinarily, this settlement payment is offset by the payment received from the customer pursuant to the associated fixed-price sales contract. We are, however, required to make the settlement payment under the futures contract even if a fixed-price sales contract customer does not perform. Nonperformance under fixed-price sales contracts by a significant number of our customers could have an adverse effect on our business, financial condition, results of operations or cash flows.

Terrorist attacks could adversely affect our business.

Since the attacks of September 11, 2001, the United States government has issued warnings that energy assets, specifically our nation s pipeline infrastructure, may be the future target of terrorist organizations. These developments have subjected our operations to increased risks. Any future terrorist attack on our facilities, those of our customers and, in some cases, those of other pipelines, refineries or terminals, could have a material adverse effect on our business, financial condition, results of operations or cash flows.

During 2007, the Department of Homeland Security promulgated the Chemical Facility Anti-Terrorism Standards (CFATS) to regulate the security of facilities considered to have high risk chemicals. We have submitted to the Department of Homeland Security certain required information concerning our facilities in compliance with CFATS and, as a result, several of our facilities have been determined to be initially tiered as high risk by the Department of Homeland Security. Due to this determination, we are required to prepare a security vulnerability assessment and possibly develop and implement site security plans required by CFATS. At this time, we do not believe that compliance with CFATS will have a material effect on our business, financial condition, results of operations or cash flows.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be insured.

Our operations are subject to operational hazards and unforeseen interruptions such as natural disasters, adverse weather, accidents, fires, explosions, hazardous materials releases and other events beyond our control. These events might result in a loss of equipment or life, injury, or extensive property damage, as well as an interruption in our operations. Our operations are currently covered by property, casualty, workers compensation and environmental insurance policies. In the future, however, we may not be able to maintain or obtain insurance of the type and amount desired at reasonable rates. As a result of market conditions, premiums and deductibles for certain insurance policies have increased substantially, and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. For example, insurance carriers are now requiring broad exclusions for losses due to war risk and terrorist acts. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position, thereby reducing our ability to make distributions to Unitholders, or payments to debt holders.

We may not be able to realize the benefits of the organizational restructuring commenced in the second quarter of 2009, which could adversely impact our business and financial results.

In the second quarter of 2009, following our comprehensive best practices review of our business, we commenced a significant organizational restructuring designed to improve efficiencies and realize cost savings. If we are unable to successfully realize the efficiencies and benefits of our reorganization, our financial results may be adversely impacted. In addition, if we are unable to successfully realize the operational benefits of our reorganization, our relationships with customers, suppliers and employees may be adversely affected.

Our natural gas storage business depends on third party pipelines to transport natural gas.

We depend on Pacific Gas and Electric s intrastate gas pipelines to move our customers natural gas to and from our Lodi Gas facility. Any interruption of service or decline in utilization on the pipelines or adverse change in the terms and conditions of service for the pipelines could have a material adverse effect on the ability of our customers to transport natural gas to and from the Lodi Gas facility, and could have a corresponding material adverse effect on our storage revenues. In addition, the rates charged by the interconnected pipelines for transportation to and from our facilities could affect the utilization and value of our storage services.

A significant decrease in the production of natural gas could have a significant financial impact on us.

Our profitability is materially affected by the volume of natural gas stored by us. A material change in the supply or demand of natural gas could result in a decline in the volume of natural gas delivered to the Lodi Gas facility for storage, and adversely impact our business, financial condition, results of operations or cash flows.

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Our results could be adversely affected by volatility in the value of natural gas storage services, including hub services.

The Natural Gas Storage segment stores natural gas for, and loans natural gas to, its customers for fixed periods of time. If the values of natural gas storage services change in a direction or manner that we do not anticipate, we could experience financial losses from these activities. Although the Natural Gas Storage segment does not purchase or sell natural gas, the value of natural gas storage services generally changes based on changes in the relative prices of natural gas over different delivery periods. In particular, the hub services portion of our Natural Gas Storage segment involves our entry into interruptible natural gas storage agreements with our customers. These agreements are entered into 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. To the extent that the seasonal price differences were to moderate, our business, financial condition, results of operations, or cash flows could be negatively impacted.

Our results could be adversely affected by volatility in the price of refined petroleum products.

The Energy Services segment buys and sells refined petroleum products in connection with its marketing activities. If the values of refined petroleum products change in a direction or manner that we do not anticipate, we could experience financial losses from these activities. Furthermore, when refined petroleum product prices increase rapidly and dramatically, we may be unable to promptly pass our additional costs to our customers, resulting in lower margins for us which could adversely affect our results of operations. It is our practice to maintain a position that is substantially balanced between commodity purchases, on the one hand, and expected commodity sales or future delivery obligations, on the other hand. Through these transactions, we seek to establish a margin for the commodity purchased by selling the same commodity for physical delivery to third party users, such as wholesalers or retailers. While our hedging policies are designed to minimize commodity risk, some degree of exposure to unforeseen fluctuations in market conditions remains. For example, any event that disrupts our anticipated physical supply could expose us to risk of loss resulting from price changes if we are required to obtain alternative supplies to cover these sales transactions. In addition, we are also exposed to basis risks in our hedging activities that arise when a commodity, such as ultra low sulfur diesel, is purchased at one pricing index but must be hedged against another commodity type, such as heating oil, because of limitations in the markets for derivative products. We are also susceptible to basis risk created when we hedge a commodity based on prices at a certain location, such as the New York Harbor, and enter into a sale or exchange of that commodity at another location, such as Macungie, Pennsylvania, where prices and price changes might differ from the prices and price changes at the location upon which the hedging instrument is based.

Our risk management policies cannot eliminate all commodity risk and any noncompliance with our risk management policies could result in significant financial losses.

Our Energy Services segment follows risk management practices that are designed to minimize its commodity risk, and the Natural Gas Storage segment has adopted risk management policies that are designed to manage the risks associated with its storage business. These practices and policies cannot, however, eliminate all price and price-related risks and there is also the risk of noncompliance with such practices and policies. We cannot make any assurances that we will detect and prevent all violations of our risk management practices and policies, particularly if deception or other intentional misconduct is involved. Any violations of these practices or policies by our employees or agents could result in significant financial losses.

Risks Relating to Partnership Structure

We may sell additional LP Units, diluting existing interests of Unitholders.

Our partnership agreement allows us to issue additional LP Units and certain other equity securities without Unitholder approval. There is no limit on the total number of LP Units and other equity securities we may issue. When we issue additional LP Units or other equity securities, the proportionate partnership interest of our existing Unitholders will decrease. The issuance could negatively affect the amount of cash distributed to Unitholders and the market price of the LP Units. Issuance of additional LP Units will also diminish the relative voting strength of the previously outstanding LP Units.

Our general partner and its affiliates may have conflicts with us.

The directors and officers of our general partner and its affiliates have fiduciary duties to manage the general partner in a manner that is beneficial to its sole member, BGH. At the same time, the general partner has fiduciary duties to manage us in a manner that is beneficial to our partners. Therefore, the general partner s duties to us may conflict with the duties of its officers and directors to its sole member.

Such conflicts may arise from, among others, the following factors:

- decisions by our general partner regarding the amount and timing of our cash expenditures, borrowings and issuances of additional LP Units or other securities can affect the amount of incentive distribution payments we make to our general partner;

- under our partnership agreement we reimburse the general partner for the costs of managing and operating us; and

- under our partnership agreement, it is not a breach of our general partner s fiduciary duties for affiliates of our general partner to engage in activities that compete with us.

Conflicts of interest with our general partner and its affiliates, including the foregoing factors, could exacerbate periods of lower or declining performance, or otherwise reduce our revenues and operating income.

A default under BGH s Credit Facility could result in a change of control of our general partner which would be an event of default under our Credit Facility.

BGH is a party to a $10.0 million credit agreement with SunTrust Bank, pursuant to which it has pledged its ownership interest in our general partner as collateral security for its obligations under this agreement. If BGH were to default on its obligations under its credit agreement, its lender could exercise its rights under this pledge which could result in a change of control of our general partner and a change of control of us. A change of control would constitute an event of default under our Credit Facility and require the administrative agent, upon request of the lenders providing a majority of the loan commitments or outstanding loan amounts, to declare all amounts payable by us under our Credit Facility immediately due and payable.

Unitholders have limited voting rights and control of management.

Our general partner manages and controls our activities. Unitholders have no right to elect the general partner or the directors of the general partner on an annual or other ongoing basis. However, if the general partner resigns or is removed, its successor must be elected by holders of a majority of the LP Units. Unitholders may remove the general partner only by a vote of the holders of at least 80% of the LP Units and only after receiving certain state regulatory approvals required for the transfer of control of a public utility. As a result, Unitholders will have limited influence on matters affecting our operations, and third parties may find it difficult to gain control of us or influence our actions.

Our partnership agreement limits the liability of our general partner.

Our general partner owes fiduciary duties to our Unitholders. Provisions of our partnership agreement and partnership agreements for each of our operating partnerships, however, contain language limiting the liability of the general partner to the Unitholders for actions or omissions taken in good faith which do not involve gross negligence or willful misconduct. In addition, these partnership agreements grant broad rights of indemnification to the general partner and its directors, officers, employees and affiliates.

Unitholders may not have limited liability in some circumstances.

The limitations on the liability of holders of limited partnership interests for the obligations of a limited partnership have not been clearly established in some states. If it were determined that we had been conducting business in any state without compliance with the applicable limited partnership statute, or that the Unitholders as a group took any action pursuant to our partnership agreement that constituted participation in the control of our business, then the Unitholders could be held liable under some circumstances for our obligations to the same extent as a general partner.

Under applicable state law, our general partner has unlimited liability for our obligations, including our debts and environmental liabilities, if any, except for our contractual obligations that are expressly made without recourse to the general partner.

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

Tax Risks to Unitholders

Unitholders are urged to read the section above entitled Tax Considerations for Unitholders for a more complete discussion of the expected material federal income tax consequences of owning and disposing of LP Units.

Our tax treatment depends on our status as a partnership for federal income tax purposes as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to additional amounts of entity-level taxation for state tax purposes, then our cash available for distribution to Unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in LP Units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested, and do not plan to request, a ruling from the IRS on this.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we are so treated, a change in our business (or a change in current law) could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

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

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. At the federal level, legislation has been proposed that would eliminate partnership tax treatment for certain publicly traded partnerships. Although such legislation would not apply to us as currently proposed, it could be amended prior to enactment in a manner that does apply to us. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in our LP Units. At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay Texas franchise tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas in the prior year. Imposition of such a tax on us by any other state will reduce the cash available for distribution to you.

If the IRS contests the federal income tax positions we take, the market for our LP Units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to you.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or certain other matters affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our LP Units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our Unitholders and our general partner because the costs will reduce our cash available for distribution.

You will be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

Because our Unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from that income.

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

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

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

Investment in our LP Units by tax-exempt entities, such as employee benefit plans and IRAs, and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file United States federal tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our LP Units.

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

Because we cannot match transferors and transferees of LP Units and because of other reasons, we have adopted depreciation and amortization positions that may not conform to all aspects of existing U.S. Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of LP Units and could have a negative impact on the value of our LP Units or result in audit adjustments to your tax returns.

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our LP Units each month based upon the ownership of our LP Units on the first day of each month, instead of on the basis of the date a particular LP Unit is transferred. The use of this proration method may not be permitted under existing U.S. Treasury regulations. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our Unitholders.

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A Unitholder whose LP Units are loaned to a short seller to cover a short sale of LP Units may be considered as having disposed of those LP Units. If so, he would no longer be treated for tax purposes as a partner with respect to those LP Units during the period of the loan and may recognize gain or loss from the disposition.

Because a Unitholder whose LP Units are loaned to a short seller to cover a short sale of LP Units may be considered as having disposed of the loaned LP Units, he may no longer be treated for tax purposes as a partner with respect to those LP Units during the period of the loan to the short seller and the Unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those LP units may not be reportable by the Unitholder and any cash distributions received by the Unitholder as to those LP Units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their LP Units.

We will adopt certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the Unitholders. The IRS may challenge this treatment, which could adversely affect the value of the LP Units.

When we issue additional LP Units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our Unitholders and Buckeye GP. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain Unitholders and Buckeye GP, which may be unfavorable to such Unitholders. Moreover, under our valuation methods, subsequent purchasers of LP Units may have a greater portion of their Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between Buckeye GP and certain of our Unitholders. A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our Unitholders. It also could affect the amount of gain from our Unitholders sale of LP Units and could have a negative impact on the value of the LP Units or result in audit adjustments to our Unitholders tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all Unitholders, which would result in us filing two tax returns (and our Unitholders could receive two Schedules K-1) for one fiscal year and could result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a Unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if the taxpayer requests relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

As a result of investing in our LP Units, you may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire property.

In addition to federal income taxes, you will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in any of those jurisdictions. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, you may be subject to penalties for failure to comply

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with those requirements. We own property and conduct business in a number of states in the United States. Most of these states impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is your responsibility to file all foreign, federal, state and local tax returns.

We have a subsidiary that is treated as a corporation for federal income tax purposes and subject to corporate-level income taxes.

We conduct a portion of our operations through a subsidiary that is a corporation for federal income tax purposes. We may elect to conduct additional operations in corporate form in the future. The corporate subsidiary will be subject to corporate-level tax, which will reduce the cash available for distribution to us and, in turn, to our Unitholders. If the IRS were to successfully assert that the corporate subsidiary has more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, our cash available for distribution would be further reduced.

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

None.

Item 2. ***Properties***

We are managed primarily from two leased commercial business offices located in Breinigsville, Pennsylvania and Houston, Texas that are approximately 75,000 and 27,000 square feet in size, respectively.

In general, our pipelines are located on land owned by others pursuant to rights granted under easements, leases, licenses and permits from railroads, utilities, governmental entities and private parties. Like other pipelines, certain of our rights are revocable at the election of the grantor or are subject to renewal at various intervals, and some require periodic payments. We have not experienced any revocations or lapses of such rights which were material to our business or operations, and we have no reason to expect any such revocation or lapse in the foreseeable future. Most delivery points, pumping stations and terminal facilities are located on land that we own. We have leases for subsurface underground gas storage rights and surface rights in connection with our operations in the Natural Gas Storage segment.

See Item 1 for a description of the location and general character of our material property.

We believe that we have sufficient title to our material assets and properties, possess all material authorizations and revocable consents from state and local governmental and regulatory authorities and have all other material rights necessary to conduct our business substantially in accordance with past practice. Although in certain cases our title to assets and properties or our other rights, including our rights to occupy the land of others under easements, leases, licenses and permits, may be subject to encumbrances, restrictions and other imperfections, we do not expect any of such imperfections to interfere materially with the conduct of our businesses.

Item 3. ***Legal Proceedings***

We, in the ordinary course of business, are involved in various claims and legal proceedings, some of which are covered in whole or in part by insurance. We are unable to predict the timing or outcome of these claims and proceedings.

With respect to environmental litigation, we have been named in the past as defendants in lawsuits, or have been notified by federal or state authorities that they are potentially responsible parties (PRPs) under federal laws or a respondent under state laws relating to the generation, disposal or release of hazardous substances into the environment. In connection with actions brought under CERCLA and similar state statutes, we are usually one of many PRPs for a particular site and our contribution of total waste at the site is usually not material.

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Although there is no material environmental litigation pending against us at this time, claims may be asserted in the future under various federal and state laws, and the amount of any potential liability associated with such claims cannot be estimated.

Item 4. ***[Reserved]***

PART II

Item 5. ***Market for the Registrant s LP Units, Related Unitholder Matters, and Issuer Purchases of LP Units***

Our LP Units are listed and traded on the NYSE under the symbol BPL. The high and low sales prices of our LP Units during the years ended December 31, 2009 and 2008, as reported in the NYSE Composite Transactions, were as follows:

	2009		2008	
Quarter	**High**	**Low**	**High**	**Low**
First	$43.25	$32.00	$51.09	$43.66
Second	43.69	35.01	50.00	42.65
Third	49.44	41.43	44.54	36.08
Fourth	57.00	47.51	42.39	22.00

We have gathered tax information from our known Unitholders and from brokers/nominees and, based on the information collected, we estimate our number of beneficial Unitholders to be approximately 95,623 at December 31, 2009.

Cash distributions paid to Unitholders for the years ended December 31, 2009 and 2008 were as follows:

Record Date	Payment Date	Amount Per LP Unit
February 12, 2009	February 27, 2009	$ 0.8875
May 11, 2009	May 29, 2009	0.9000
August 7, 2009	August 31, 2009	0.9125
November 7, 2009	November 28, 2009	0.9250
February 5, 2008	February 29, 2008	$ 0.8375
May 9, 2008	May 30, 2008	0.8500
August 8, 2008	August 29, 2008	0.8625
November 7, 2008	November 28, 2008	0.8750

On February 5, 2010, we announced a quarterly distribution of $0.9375 per LP Unit that was paid on February 26, 2010, to Unitholders of record on February 16, 2010. Total cash distributed to Unitholders on February 26, 2010 was approximately $60.8 million.

We generally make quarterly cash distributions of substantially all of our available cash, generally defined as consolidated cash receipts less consolidated cash expenditures and such retentions for working capital, anticipated cash expenditures and contingencies as Buckeye GP deems appropriate. Distributions of cash paid by us to a Unitholder will not result in taxable gain or income except to the extent the aggregate amount distributed exceeds the tax basis of the LP Units owned by the Unitholder.

We are a publicly traded MLP and are not subject to federal income tax. Instead, Unitholders are required to report their allocable share of our income, gain, loss and deduction, regardless of whether we make distributions. We have made quarterly distribution payments since May 1987.

Recent Sales of Unregistered Securities

None.

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Units Authorized for Issuance under Equity Compensation Plan

Please read the information included under Item 12 of this Report, which is incorporated by reference into this Item 5.

Issuer Purchases of Equity Securities

None.

Item 6. *Selected Financial Data*

The following tables set forth, for the periods and at the dates indicated, our selected consolidated financial data for each of the last five years which is derived from our audited consolidated financial statements. The tables should be read in conjunction with the consolidated financial statements and notes thereto included elsewhere in this Report (in thousands, except per LP Unit amounts).

	Year Ended December 31,				
	2009	**2008**	**2007**	**2006**	**2005**
Income Statement Data:					
Revenue (1)	$1,770,372	$1,896,652	$ 519,347	$ 461,760	$ 408,446
Depreciation and amortization	59,164	55,299	44,651	44,039	36,760
Asset impairment expense	59,724				
Reorganization expense	32,057				
Operating income (1) (2)	208,443	253,621	202,080	177,067	161,313
Interest and debt expense	74,851	74,387	50,378	52,113	43,357
Net income (1) (2)	146,900	189,881	160,617	114,840	103,716
Net income attributable to Buckeye Partners, L.P.	140,982	184,389	155,356	110,240	99,958
Earnings per LP Unit diluted (3)	$ 1.84	$ 3.00	$ 2.91	$ 2.14	$ 2.12
Distributions per LP Unit	$ 3.63	$ 3.43	$ 3.23	$ 3.03	$ 2.83

	December 31,				
	2009	**2008**	**2007**	**2006**	**2005**
Balance Sheet Data:					
Total assets (1)	$3,255,649	$3,034,410	$2,133,652	$1,995,470	$1,816,867
Long-term debt	1,498,970	1,445,722	849,177	994,127	899,077
General Partner s capital (deficit)	1,849	(6,680)	(1,005)	1,964	2,529
Limited Partners capital	1,214,136	1,201,144	1,100,346	807,488	756,531
Accumulated other comprehensive income (loss)	(847)	(18,967)	(9,169)	785	
Noncontrolling interests (4)	20,957	20,775	21,468	20,169	19,516

(1) Substantial increases in revenue, operating income, net income and total assets for the year ended December 31, 2007 through

the year ended December 31, 2008 resulted from the acquisitions of Lodi Gas and Farm & Home in the first quarter of 2008. See Note 4 in the Notes to Consolidated Financial Statements for further discussion.

(2) Operating income and net income for the year ended December 31, 2009 include a non-cash charge of $59.7 million related to an asset impairment (see Note 8 in the Notes to Consolidated Financial Statements) and $32.1 million of expenses incurred in connection with an organization restructuring (see Note 3 in the Notes to Consolidated Financial Statements).

(3) For periods prior to January 1, 2009, earnings per LP Unit has been restated due to

the adoption of guidance regarding the calculation of earnings per LP Unit as it relates to MLPs. See Note 22 in the Notes to Consolidated Financial Statements for further information.

(4) For periods prior to January 1, 2009, noncontrolling interests liability has been reclassified into partners capital on the consolidated balance sheets due to the adoption of guidance regarding accounting and reporting standards for the noncontrolling interests in a subsidiary. See Note 2 in the Notes to Consolidated Financial Statements for further information.

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

The following information should be read in conjunction with our consolidated financial statements and our accompanying notes thereto included in Item 8 of this Report. Our discussion and analysis includes the following:

- Overview of Business;
- General Outlook for 2010;
- 2009 Developments discusses major items impacting our results in 2009;
- Results of Operations discusses material year-to-year variances in the consolidated statements of operations;
- Liquidity and Capital Resources addresses available sources of liquidity and capital resources and includes a discussion of our capital spending;
- Critical Accounting Policies and Estimates presents accounting policies that are among the most critical to the portrayal of our financial position and results of operations;
- Other Items includes information related to contractual obligations, off-balance sheet arrangements and other matters; and
- Recent Accounting Pronouncements.

This discussion contains forward-looking statements based on current expectations that are subject to risks and uncertainties, such as statements of our plans, objectives, expectations and intentions. Our actual results and the timing of events could differ materially from those anticipated or implied by the forward-looking statements discussed here as a result of various factors, including, among others, those set forth under Cautionary Note Regarding Forward-Looking Statements and Risk Factors herein.

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

Overview of Business

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 Unitholders.

We operate and report in five business segments: Pipeline Operations; Terminalling and Storage; Natural Gas Storage; Energy Services; and Development and Logistics. We previously referred to the Development and Logistics segment as the Other Operations segment. We renamed the segment to better describe the business activities conducted within the segment. See Note 23 in the Notes to Consolidated Financial Statements for a more detailed discussion of our business segments.

Our principal line of business is the transportation, terminalling, storage and marketing of refined petroleum products in the United States for major integrated oil companies, large refined petroleum product marketing companies and major end users of refined petroleum products on a fee basis through facilities we own and operate. We own a major natural gas storage facility in northern California. We also operate pipelines owned by third parties under contracts with major integrated oil and chemical companies, and perform certain construction activities, generally for the owners of those third-party pipelines.

General Outlook for 2010

During 2008 and 2009, demand for refined petroleum products was adversely impacted by the slowdown in the overall economy. In 2010, however, we anticipate that demand will level out as underlying economic conditions stabilize or improve. We expect that the aggregate rates for our transportation and storage services in 2010 will show modest increases despite the impact of negative economic conditions during 2009. Ultimately, our ability to

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maintain or increase transportation and storage volumes and rates in 2010 will be largely dependent upon the strength of the overall economy and demand for refined petroleum products in the areas we serve.

The capital markets strengthened considerably in 2009, compared to 2008, and we successfully accessed both the debt and equity markets to fund our 2009 growth initiatives. Although we have no specific plans to access the capital markets in 2010, should we elect to raise capital, we believe that, under current financial market conditions, we would be able to raise capital in both the debt and equity markets on acceptable terms.

We expect that our earnings in 2010 will be positively impacted by the full year contribution from the refined petroleum products pipelines and terminals acquired from ConocoPhillips in November 2009, cost savings from the organizational restructuring completed in 2009, and incremental revenue from growth capital expenditures in 2009 and 2010.

Throughout 2010, we will continue to evaluate opportunities to acquire or construct assets that are complementary to our business and support our long term growth strategy and will determine the appropriate financing structure for any opportunity we pursue.

2009 Developments

Major items impacting our results in 2009 include:

Consolidated Statements of Operations

In early 2009, we began a best practices review of our business and organization structure to identify improved business practices, operating efficiencies and cost savings in anticipation of changing needs in the energy markets. This review culminated in the approval by the Board of Directors of Buckeye GP of an organizational restructuring. The organizational restructuring included a workforce reduction of approximately 230 employees, in excess of 20% of our workforce. The program was initiated in the second quarter of 2009 and was substantially complete by the end of 2009. As part of the workforce reduction, we offered certain eligible employees the option of enrolling in a voluntary early retirement program, which approximately 80 employees accepted. The remaining affected positions have been eliminated involuntarily under our ongoing severance plan. Most terminations were effective as of July 20, 2009. The restructuring also included the relocation of some employees consistent with the goals of the reorganization. We have incurred $32.1 million of expenses in connection with this organizational restructuring for the year ended December 31, 2009. See Note 3 in the Notes to Consolidated Financial Statements for further discussion.

We recorded a non-cash charge of $59.7 million during the year ended December 31, 2009 related to an impairment of Buckeye NGL. During the second quarter of 2009, we recorded a non-cash charge of $72.5 million. Effective January 1, 2010, we sold our interest in Buckeye NGL for $22.0 million. The sales proceeds exceeded the previously impaired carrying value of the NGL pipeline by $12.8 million resulting in the reversal of $12.8 million of the previously recorded asset impairment expense in the fourth quarter of 2009. The impairment and subsequent reversal is reflected within the category Asset Impairment Expense on our consolidated statements of operations. See Note 8 in the Notes to Consolidated Financial Statements for further discussion.

We experienced a delay in the startup of the Kirby Hills Phase II expansion project in our Natural Gas Storage segment, which we initially expected to occur in April 2009. The project was ultimately placed into service in June 2009.

We experienced lower Pipeline Operations product transportation volumes of 5.2% in 2009 as compared to 2008, which resulted in an approximate $19.0 million reduction in revenues.

We recorded a favorable property tax settlement of $7.2 million from the City of New York in our Pipeline Operations segment, which is reflected within the category Total costs and expenses in our consolidated statements of operations.

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Consolidated Balance Sheet and Capital Structure

We completed an acquisition in 2009 of certain refined petroleum product terminals and pipeline assets from ConocoPhillips for approximately $54.4 million that was financed with borrowings under our Credit Facility.

We incurred capital expenditures for internal growth projects of $63.8 million.

We sold $275.0 million aggregate principal amount of 5.500% Notes due 2019 for net proceeds of $271.4 million in an underwritten public offering.

We issued approximately 3.0 million LP Units in 2009 for net proceeds of approximately $104.6 million in an underwritten public offering.

We amended the BES Credit Agreement to increase the borrowing capacity from $175.0 million to $250.0 million. Our Credit Facility was also amended to reduce the borrowing capacity from $600.0 million to $580.0 million.

Results of Operations

Consolidated Summary

Adjusted EBITDA (as defined below) increased during the year ended December 31, 2009 compared to the year ended December 31, 2008 and during the year ended December 31, 2008 compared to the year ended December 31, 2007. Our revenues, operating income, net income and earnings per LP Unit decreased during the year ended December 31, 2009 compared to the year ended December 31, 2008, primarily due to the recognition of expenses in connection with our organizational restructuring, a non-cash charge for an asset impairment and, in the case of our revenue decrease, lower overall pipeline and terminalling and storage volumes resulting in lower revenues. Our revenues, operating income, net income and earnings per LP Unit increased during the year ended December 31, 2008 compared to the year ended December 31, 2007, primarily due to the expansion of our operations through acquisitions and to increases in interstate pipeline tariff rates and terminalling throughput fees. Overall pipeline volumes declined by 5.2% during the year ended December 31, 2009 compared to the year ended December 31, 2008 and 4.5% during the year ended December 31, 2008 compared to the year ended December 31, 2007.

Our summary operating results were as follows for the periods indicated (in thousands):

	Year Ended December 31,		
	2009	**2008**	**2007**
Revenues	$ 1,770,372	$ 1,896,652	$ 519,347
Costs and expenses	1,561,929	1,643,031	317,267
Operating income	208,443	253,621	202,080
Earnings from equity investments	12,531	7,988	7,553
Interest and debt expense	(74,851)	(74,387)	(50,378)
Other income	777	1,429	1,362
Income from continuing operations	146,900	188,651	160,617
Income from discontinued operations		1,230	
Net income	146,900	189,881	160,617
Less: net income attributable to noncontrolling interests (1)	(5,918)	(5,492)	(5,261)
Net income attributable to Buckeye Partners, L.P.	$ 140,982	$ 184,389	$ 155,356
Earnings per LP Unit diluted (2)	$ 1.84	$ 3.00	$ 2.91

(1) Net income attributable to noncontrolling interests has been restated due to the adoption of guidance regarding accounting and reporting standards for the noncontrolling interests in a subsidiary (see Note 2 in the Notes to Consolidated Financial Statements for further information).

(2) Earnings per LP Unit has been restated due to the adoption of guidance regarding the calculation of earnings per unit as it relates to MLPs (see Note 22 in the Notes to Consolidated Financial Statements for further information).

Adjusted EBITDA

In the first quarter of 2009, we revised our internal management reports to provide senior management, including the Chief Executive Officer, more information about Adjusted EBITDA (as defined below). Adjusted EBITDA is now 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 from continuing operations 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 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. In addition, we have excluded the Buckeye NGL impairment expense of $59.7 million and the reorganization expense of $32.1 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 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.

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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).

	Year Ended December 31,		
	2009	**2008**	**2007**
Adjusted EBITDA:			
Pipeline Operations	$ 230,172	$ 196,852	$ 192,236
Terminalling and Storage	72,518	60,410	49,363
Natural Gas Storage	42,214	42,374	
Energy Services	19,419	9,818	
Development and Logistics	6,607	8,785	9,549
Total Adjusted EBITDA	$ 370,930	$ 318,239	$ 251,148
GAAP Reconciliation:			
Net income	$ 146,900	$ 189,881	$ 160,617
Less: net income attributable to noncontrolling interests	(5,918)	(5,492)	(5,261)
Less: Income from discontinued operations		(1,230)	
Net income attributable to Buckeye Partners, L.P. unitholders from continuing operations	140,982	183,159	155,356
Interest and debt expense	74,851	74,387	50,378
Income tax expense (benefit)	(348)	796	763
Depreciation and amortization	59,164	55,299	44,651
EBITDA	274,649	313,641	251,148
Non-cash deferred lease expense	4,500	4,598	
Asset impairment expense	59,724		
Reorganization expense	32,057		
Adjusted EBITDA	$ 370,930	$ 318,239	$ 251,148

Segment Results

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

	Year Ended December 31,		
	2009	2008	2007
Revenues:			
Pipeline Operations	$ 392,667	$ 387,267	$ 379,345
Terminalling and Storage	136,576	119,155	103,782
Natural Gas Storage	99,163	61,791	
Energy Services	1,125,013	1,295,925	
Development and Logisitics	34,136	43,498	36,220
Intersegment	(17,183)	(10,984)	
Total revenues	$ 1,770,372	$ 1,896,652	$ 519,347
Total costs and expenses: (1)			
Pipeline Operations	$ 295,984	$ 234,017	$ 229,050
Terminalling and Storage	74,626	65,451	60,939
Natural Gas Storage	68,415	29,099	
Energy Services	1,111,492	1,289,886	
Development and Logisitics	28,595	35,562	27,278
Intersegment	(17,183)	(10,984)	
Total costs and expenses	$ 1,561,929	$ 1,643,031	$ 317,267
Depreciation and amortization:			
Pipeline Operations	$ 38,434	$ 38,279	$ 37,411
Terminalling and Storage	7,851	6,583	5,610
Natural Gas Storage	6,458	5,003	
Energy Services	4,547	3,683	
Development and Logisitics	1,874	1,751	1,630
Total depreciation and amortization	$ 59,164	$ 55,299	$ 44,651
Asset impairment expense:			
Pipeline Operations	$ 59,724	$	$
Reorganization expense:			
Pipeline Operations	$ 26,127	$	$
Terminalling and Storage	2,735		
Natural Gas Storage	495		
Energy Services	1,207		
Development and Logisitics	1,493		
Total reorganization expense	$ 32,057	$	$
Operating income:			
Pipeline Operations	$ 96,683	$ 153,250	$ 150,295

Terminalling and Storage	61,950	53,704	42,843
Natural Gas Storage	30,748	32,692	
Energy Services	13,521	6,039	
Development and Logisitics	5,541	7,936	8,942
Total operating income	$ 208,443	$ 253,621	$ 202,080

(1) Includes depreciation and amortization, asset impairment expense and reorganization expense.

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

	Year Ended December 31,		
	2009	2008	2007
Pipeline Operations: (average barrels per day)			
Gasoline	650,100	673,500	717,900
Distillate	284,700	304,200	320,100
Jet Fuel	336,700	354,700	362,700
LPGs	16,500	17,500	19,300
NGLs	13,900	20,900	20,400
Other products	8,000	11,400	7,000
Total Pipeline Operations	1,309,900	1,382,200	1,447,400
Terminalling and Storage: (average barrels per day)			
Products throughput (1)	444,900	457,400	482,300
Energy Services: (in thousands of gallons)			
Sales volumes (2)	655,100	435,200	

(1) Reported quantities exclude transfer volumes, which are non-revenue generating transfers among our various terminals. For the years ended December 31, 2008 and 2007, we previously reported 537.7 thousand and 568.6 thousand barrels, respectively, which included transfer volumes.

(2) Our Energy Services

segment
business was
acquired on
February 8,
2008.

2009 Compared to 2008

Consolidated

Adjusted EBITDA increased by $52.7 million or 16.6% to $370.9 million during the year ended December 31, 2009 from $318.2 million in the corresponding period in 2008. The Pipeline Operations segment, the Terminalling and Storage segment and the Energy Services segment contributed to this increase in Adjusted EBITDA. The Pipeline Operations segment s Adjusted EBITDA increased $33.4 million despite lower transportation volumes in 2009 as compared to 2008. This shortfall in volumes was offset by increased tariffs, more favorable settlement experience and lower overall operating expenses. The Terminalling and Storage segment s Adjusted EBITDA increased $12.1 million primarily due to terminals acquired at various times in 2008 and in November of 2009 and growth in other terminalling and storage revenues, partially offset by less favorable settlement experience. The Energy Services segment s Adjusted EBITDA increased $9.6 million as a result of increased volumes and improved margins. The Natural Gas Storage segment s Adjusted EBITDA decreased $0.2 million in 2009 as compared to 2008 due to increased expenses associated with certain hub services transactions stemming from delays in the start-up of the Kirby Hills Phase II expansion project and general market conditions. The Development and Logistics segment s Adjusted EBITDA decreased $2.2 million as a result of reduced operating services and construction revenues. Further contributing to the increase in consolidated Adjusted EBITDA was the continued effectiveness of cost control measures we implemented in 2009. Largely as a result of these efforts, combined with the delay of certain non-critical maintenance activities, overall spending levels decreased $5.0 million in 2009 compared to 2008. Income from equity investments increased $4.5 million in 2009 compared to 2008. The revenue and expense factors affecting the variance in consolidated Adjusted EBITDA are more fully discussed below.

Revenue was $1,770.4 million for the year ended December 31, 2009, which is a decrease of $126.3 million or 6.7% from the year ended December 31, 2008. This overall decrease was caused primarily by a decrease in revenues from the Energy Services segment of $170.9 million due to an overall reduction in refined petroleum product prices in 2009 as compared to 2008, and a decrease in the Development and Logistics segment s revenue of $9.4 million primarily due to decreased construction activities. This decrease was partially offset by increased revenues from the Natural Gas Storage segment of $37.4 million from increased activity from the commencement of operations of the Kirby Hills Phase II expansion project, increased revenues from the Terminalling and Storage segment of $17.4 million primarily from terminals acquired at various times in 2008 and in November of 2009, fees and storage and rental revenue growth and increased revenues from the Pipeline Operations segment of $5.4 million primarily due to increased tariffs and more favorable settlement experience, partially offset by lower volumes.

Total costs and expenses were $1,561.9 million for the year ended December 31, 2009, which is a decrease of $81.2 million or 4.9% from the corresponding period in 2008. Total costs and expenses reflect a decrease in refined petroleum product prices, which resulted in a $178.4 million decrease in the Energy Services segment s cost of product sales in 2009 as compared to 2008, partially offset by increased volumes in 2009. In addition, total costs and expenses reflect the effectiveness of overall cost management efforts we implemented in 2009. These decreases in total costs and expenses were partially offset by a $59.7 million asset impairment expense, a $32.1 million reorganization expense (see Notes 8 and 3, respectively, in the Notes to Consolidated Financial Statements) and a $3.9 million increase in depreciation and amortization, which are not components of Adjusted EBITDA as presented in the reconciliation above. Other factors impacting total costs and expenses include increased operating costs for terminals acquired at various times in 2008 and in November of 2009 in the Terminalling and Storage segment and increased expenses associated with certain hub services transactions stemming from delays in the Kirby Hills Phase II expansion project in the Natural Gas Storage segment and general market conditions.

As described in Note 1 in the Notes to Consolidated Financial Statements, effective January 1, 2009, we and our Operating Subsidiaries began paying for all executive compensation and benefits earned by Buckeye GP s four highest salaried officers in return for an annual fixed payment from BGH of $3.6 million. The $3.6 million annual fixed payment consists of the anticipated 2009 salaries, incentive compensation and benefits of these officers plus 15%. Salaries and benefits for 2009 include salaries, incentive compensation and benefits of these officers offset by the $3.6 million annual fixed payment.

Consolidated income from continuing operations attributable to our Unitholders was $141.0 million for the year ended December 31, 2009 compared to $183.2 million for the year ended December 31, 2008. The current period results also include an increase of $0.5 million in interest and debt expense from $74.4 million in 2008 largely attributable to the issuance of the 5.500% Notes. In addition, depreciation and amortization increased by $3.9 million, primarily due to acquisitions made during 2008, the assets utilized with respect to the Kirby Hills Phase II expansion project which were placed in service in the second half of 2009 and software which was placed in service in the fourth quarter of 2009.

Pipeline Operations

Adjusted EBITDA from the Pipeline Operations segment of $230.2 million increased during the year ended December 31, 2009 by $33.4 million or 16.9% from $196.8 million during the year ended December 31, 2008. The increase in Adjusted EBITDA was driven primarily by the benefit of increased tariffs and more favorable settlement experience of $37.3 million, partially offset by a $19.0 million decrease due to the impact of lower volumes and a $0.6 million decrease in miscellaneous revenue. Increased income from equity investments of $4.5 million, a favorable property tax settlement of $7.2 million and a decrease in maintenance and other expenses totaling $4.5 million also contributed to the Pipeline Operations segment s improvement in Adjusted EBITDA. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue was $392.7 million for the year ended December 31, 2009, which is an increase of $5.4 million or 1.4% from the corresponding period in 2008. Net transportation revenues were up $20.4 million, primarily due to increased tariffs and settlement experience of $37.3 million, partially offset by a $19.0 million decrease due to a 5.2% decrease in transportation volumes. Tariff increases of 3.7% and 3.8% were implemented on January 1, 2009 and July 1, 2009, respectively. Revenues from a product supply arrangement, rentals and other incidental services decreased $15.1 million from the prior year period. The decrease in these revenues is primarily a result of reduced product volumes sold to a wholesale distributor and a decrease in contract service activities at customer facilities connected to our refined petroleum products pipelines.

Total costs and expenses were $296.0 million for the year ended December 31, 2009, which is an increase of $62.0 million or 26.5% from the corresponding period in 2008. Total costs and expenses include $59.7 million of asset impairment expense and $26.2 million of reorganization expense (see Notes 8 and 3, respectively, in the Notes

to Consolidated Financial Statements), which are not components of Adjusted EBITDA as presented in the reconciliation above. Total costs and expenses also include decreases in (i) property taxes of $6.6 million primarily due to a favorable property tax settlement with the City of New York of $7.2 million (see Note 5 in the Notes to Consolidated Financial Statements); (ii) product costs of $12.0 million as a result of reduced product volumes sold to a wholesale distributor; (iii) contract service activities of $2.9 million at customer facilities connected to our refined petroleum products pipelines; (iv) operating power of $2.8 million due to a decrease in volumes; and (v) professional fees of $1.7 million. These decreases were partially offset by an increase of $2.7 million in integrity program expenditures.

Operating income was $96.7 million for the year ended December 31, 2009 compared to operating income of $153.3 million for the year ended December 31, 2008. $59.7 million and $26.2 million of the decrease is due to the asset impairment expense and reorganization expense, respectively, discussed above. Depreciation and amortization of $38.4 million for the year ended December 31, 2009 was consistent with 2008. Other revenue and expense items impacting operating income are discussed above.

Terminalling and Storage

Adjusted EBITDA from the Terminalling and Storage segment of $72.5 million increased during the year ended December 31, 2009 by $12.1 million or 20.0% from $60.4 million during the year ended December 31, 2008. The increase in Adjusted EBITDA reflects the contribution from terminals acquired in 2009 and 2008 of $9.6 million, including the terminals acquired from ConocoPhillips in November 2009 (see Note 4 in the Notes to Consolidated Financial Statements) and increased fees and storage and rental revenue growth of $14.1 million, offset by a $10.2 million reduction due to lower settlement experience and lower terminal volumes and higher expenses of $1.4 million. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue was $136.6 million for the year ended December 31, 2009, which is an increase of $17.4 million or 14.6% from the corresponding period in 2008. This increase resulted primarily from $13.5 million of revenue in 2009 from terminals that were acquired at various times in 2008 and in November of 2009 (see Note 4 in the Notes to Consolidated Financial Statements for terminal acquisitions) and increased fees and storage and rental revenue of $14.1 million. These increases were partially offset by a $7.9 million decrease in settlement experience and a 2.7% decrease in terminal volumes resulting in a $2.3 million decrease in revenues in 2009 as compared to 2008.

Total costs and expenses were $74.6 million for the year ended December 31, 2009, which is an increase of $9.1 million or 14.0% from the corresponding period in 2008. Total costs and expenses include $2.7 million of reorganization expense (see Note 3 in the Notes to Consolidated Financial Statements) and an increase of $1.3 million in depreciation and amortization, which are not components of Adjusted EBITDA as presented in the reconciliation above. Total costs and expenses also include an increase of $4.5 million of operating expenses for terminals acquired at various times in 2008 and in November of 2009 and an increase in remediation expenses and integrity program expenditures totaling $2.3 million.

Operating income was $62.0 million for the year ended December 31, 2009 compared to operating income of $53.7 million for the year ended December 31, 2008. Depreciation and amortization increased $1.3 million for the year ended December 31, 2009 as a result of terminals acquired at various times in 2008. Other revenue and expense items impacting operating income are discussed above.

Natural Gas Storage

Adjusted EBITDA from the Natural Gas Storage segment of $42.2 million decreased during the year ended December 31, 2009 by $0.2 million or 0.4% from $42.4 million during the year ended December 31, 2008. The decrease in Adjusted EBITDA was primarily a result of increased expenses from certain hub services transactions stemming from delays in the Kirby Hills Phase II expansion project and general market conditions. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue was $99.2 million for the year ended December 31, 2009, which is an increase of $37.4 million or 60.5% from the corresponding period in 2008. This overall increase resulted primarily from increased hub services revenues in 2009 driven by increased activity from the operations of the Kirby Hills Phase II expansion project,

which was placed in service in June 2009, and the inclusion of a full year of revenue in 2009 compared to approximately eleven and one half months in the corresponding period in 2008, reflecting our purchase of Lodi Gas on January 18, 2008. Lease revenue increased $5.9 million and hub services and other revenue increased $31.5 million from the year ended December 31, 2008.

Total costs and expenses were $68.4 million for the year ended December 31, 2009, which is an increase of $39.3 million or 135.1% from the corresponding period in 2008. Total costs and expenses include $0.5 million of reorganization expense (see Note 3 in the Notes to Consolidated Financial Statements) and an increase of $1.5 million in depreciation and amortization, which are not components of Adjusted EBITDA as presented in the reconciliation above. Total costs and expenses include expenses from certain hub services transactions stemming from delays in the Kirby Hills Phase II expansion project and from general market conditions, increased costs from the operations of the Kirby Hills Phase II expansion project for the second half of 2009 when it was placed into service and expenses related to the timing of the acquisition of Lodi Gas, which was included in our results for a full year of activity in 2009 versus eleven and one half months in 2008.

Operating income was $30.7 million for the year ended December 31, 2009 compared to operating income of $32.7 million for the year ended December 31, 2008. Depreciation and amortization increased $1.5 million for 2009 from the corresponding period in 2008 due to depreciation expense on the assets utilized with respect to the Kirby Hills Phase II expansion project, which was placed in service in the second half of 2009. Other revenue and expense items impacting operating income are discussed above.

Energy Services

Adjusted EBITDA from the Energy Services segment of $19.4 million increased during the year ended December 31, 2009 by $9.6 million or 97.8% from $9.8 million during the year ended December 31, 2008. This increase in Adjusted EBITDA was a result of a 50.5% increase in sales volume and improved margins. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue was $1,125.0 million for the year ended December 31, 2009, which is a decrease of $170.9 million or 13.2% from the corresponding period in 2008. This overall decrease was primarily due to a decline in refined petroleum product prices, which correspondingly lowers the cost of products sales, partially offset by a 50.5% increase in volumes due to increased sales activity and the inclusion of a full year in 2009 compared to approximately ten and one half months in the corresponding period in 2008 following the acquisition of Farm & Home.

Total costs and expenses were $1,111.5 million for the year ended December 31, 2009, which is a decrease of $178.4 million or 13.8% from the corresponding period in 2008. Total costs and expenses include $1.2 million of reorganization expense (see Note 3 in the Notes to Consolidated Financial Statements) and an increase of $0.8 million in depreciation and amortization, which are not components of Adjusted EBITDA as presented in the reconciliation above. Total costs and expenses include a decrease of $182.7 million in cost of product sales primarily related to a decrease in commodity prices in 2009 as compared to the same period in 2008. This decrease in total costs and expenses was partially offset by the inclusion of a full year of operations in 2009 compared to approximately ten and one half months in the corresponding period in 2008 following the acquisition of Farm & Home.

Operating income was $13.5 million for the year ended December 31, 2009 compared to operating income of $6.0 million for the year ended December 31, 2008. Depreciation and amortization increased $0.8 million for 2009 from the corresponding period in 2008 due to amortization of software that was placed in service in the fourth quarter of 2009. Other revenue and expense items impacting operating income are discussed above.

Development and Logistics

Adjusted EBITDA from the Development and Logistics segment of $6.6 million decreased during the year ended December 31, 2009 by $2.2 million or 24.8% from $8.8 million during the year ended December 31, 2008. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue, which consists principally of our contract operations and engineering services for third-party pipelines, was $34.1 million for the year ended December 31, 2009, which is a decrease of $9.4 million or 21.5% from the corresponding period in 2008. The decrease in revenues resulted from reduced operating services and a reduction in construction contract revenues, reflecting a customer s termination of a contract in the second quarter of 2008. These construction activities are principally conducted on a time and material basis.

Total costs and expenses were $28.6 million for the year ended December 31, 2009, which is a decrease of $7.0 million or 19.6% from the corresponding period in 2008. Total costs and expenses include $1.5 million of reorganization expense (see Note 3 in the Notes to Consolidated Financial Statements), which is not a component of Adjusted EBITDA as presented in the reconciliation above. The decrease in total costs and expenses compared to 2008 are a result of reduced operating expenses associated with a terminated customer contract, reduced construction contract activity and reduced operating services activities.

Operating income was $5.5 million for the year ended December 31, 2009 compared to operating income of $7.9 million for the year ended December 31, 2008. Depreciation and amortization of $1.9 million for the year ended December 31, 2009 was relatively consistent with the same period in 2008, and income taxes decreased $1.1 million for the year ended December 31, 2009 due to lower earnings in the 2009 period. Other revenue and expense items impacting operating income are discussed above.

2008 Compared to 2007

Consolidated

Adjusted EBITDA increased by $67.1 million or 26.7% to $318.2 million for the year ended December 31, 2008 from $251.1 million for the year ended December 31, 2007. All of our business segments, except for the Development and Logistics segment, contributed to this increase in Adjusted EBITDA. Adjusted EBTIDA for the Natural Gas Storage and Energy Services segments, which include the Lodi Gas and Farm & Home acquisitions on January 18, 2008 and February 8, 2008, respectively, was $42.4 million and $9.8 million for the year ended December 31, 2008, respectively. The Terminalling and Storage segment s Adjusted EBITDA increased $11.0 million for the year ended December 31, 2008 primarily due to terminals acquired at various times in 2008 and 2007 and growth in other terminalling and storage revenues. The Pipeline Operations segment s Adjusted EBITDA increased $4.6 million despite lower transportation volumes for the year ended December 31, 2008 as compared to the year ended December 31, 2007. The shortfall in volumes was offset by increased tariffs and incidental revenues, partially offset by increases in operating expenses. The Development and Logistics segment s Adjusted EBITDA decreased $0.7 million primarily due to increased operating expenses. Income from equity investments increased $0.4 million primarily due to increased equity income earned from our interest in WT LPG. The revenue and expense factors affecting the variance in consolidated Adjusted EBITDA are more fully discussed below.

Revenue was $1,896.7 million for the year ended December 31, 2008, which is an increase of $1,377.3 million or 265.2% from the year ended December 31, 2007. This overall increase was caused primarily by revenues from our Energy Services and Natural Gas Storage segments of $1,295.9 million and $61.8 million due to the acquisitions of Farm & Home and Lodi Gas, respectively, in 2008. The Terminalling and Storage segment revenues increased $15.4 million from the acquisition of terminals in 2008 and 2007, and the Pipeline Operations segment revenues increased $7.9 million due to increased tariffs. The Development and Logistics segment reported higher revenue of $7.3 million due to increased construction activities.

Total costs and expenses were $1,643.1 million for the year ended December 31, 2008, which is an increase of $1,325.8 million or 417.9% from the year ended December 31, 2007. Total costs and expenses include expenses of $1,289.9 million and $29.1 million due to the acquisitions for Farm & Home and Lodi Gas, respectively, in 2008 in the Energy Services segment and the Natural Gas Storage segment, respectively. Total costs and expenses also includes increased payroll and benefits expenses resulting primarily from an increase in the number of employees

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due to our expanded operations, increased casualty losses due to an increase in the cost of remediating environmental incidents and increased construction management costs resulting from an increase in construction contracts that were substantially completed at December 31, 2008, partially offset by a decrease in pipeline and terminal maintenance activities, decreased operating power costs due to lower volumes transported in the Pipeline Operations segment, and decreased supplies expenses due to decreased throughput at our terminals in the Terminalling and Storage segment.

Consolidated net income from continuing operations attributable to our Unitholders was $183.2 million for the year ended December 31, 2008 compared to $155.4 million for the year ended December 31, 2007. The 2008 period results also include an increase of $24.0 million in interest and debt expense from $50.4 million in 2007. Approximately $17.7 million of the increase was attributable to expenses associated with the 6.05% Notes, which were issued in January 2008. The remainder of the increase is due to interest expense related to working capital requirements of the Energy Services segment and amounts outstanding under our Credit Facility. In addition, depreciation and amortization increased by $10.6 million due to acquisitions made during 2008.

Pipeline Operations

Adjusted EBITDA from the Pipeline Operations segment of $196.8 million increased during the year ended December 31, 2008 by $4.6 million or 2.4% from $192.2 million during the year ended December 31, 2007. The increase in Adjusted EBITDA was driven primarily by increased net transportation revenues and incidental revenues and lower pipeline terminal and maintenance expense and power costs, offset by reduced transportation volumes, increased fuel purchases related to a product supply arrangement and increased casualty losses. Income from equity investments increased $0.4 million. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue was $387.3 million for the year ended December 31, 2008, which is an increase of $7.9 million or 2.1% from the corresponding period in 2007. Net transportation revenues increased $1.2 million in 2008 compared to 2007 primarily as a result of tariff increases implemented on May 1, 2008 and July 1, 2008. The benefit of the tariff increases were substantially offset by reduced product volumes of 4.5% in 2008 as compared to 2007. We believe that the reduced volumes in 2008 were caused primarily by reduced demand for gasoline resulting from higher retail gasoline prices, reduced production at ConocoPhillip s Wood River Refinery due to maintenance activities, and the continued introduction of ethanol into retail gasoline products as well as reduced demand for distillates resulting from higher retail distillate prices and the slowdown in the U.S. economy. Incidental revenues increased $4.7 million principally related to a product supply arrangement, and revenues from additional construction management and rental revenues increased $1.5 million from the corresponding period in 2007.

Total costs and expenses were $234.0 million for the year ended December 31, 2008, which is an increase of $5.0 million or 2.2% from the corresponding period in 2007. Total costs and expenses include depreciation and amortization which is not a component of Adjusted EBITDA. The increase in total costs and expenses is primarily attributable to: (i) an increase of $4.6 million primarily associated with fuel purchases related to a product supply arrangement; (ii) an increase of $2.3 million in casualty losses, which is due to an increase in the cost of remediating environmental incidents compared to 2007, as well as $0.5 million related to a product contamination incident that occurred in the third quarter of 2008; and (iii) an increase of $1.2 million in payroll and payroll benefits primarily resulting from an increase in the number of employees due to our expanded operations. These increases were partially offset by a decrease of $2.8 million in pipeline maintenance activities compared to 2007 and a decrease of $1.0 million in operating power costs due to lower volumes transported.

Operating income was $153.3 million for the year ended December 31, 2008 compared to operating income of $150.3 million for the year ended December 31, 2007. Depreciation and amortization increased $0.9 million for the year ended December 31, 2008 from the corresponding period in 2007 due to our ongoing expansion capital program. Other revenue and expense items impacting operating income are discussed above.

Terminalling and Storage

Adjusted EBITDA from the Terminalling and Storage segment of $60.4 million increased during the year ended December 31, 2008 by $11.0 million or 22.4% from $49.4 million during the year ended December 31, 2007. The increase in Adjusted EBITDA reflects the contribution of revenues from terminals acquired during 2007 and 2008 of $6.5 million, partially offset by an increase of $2.1 million in operating expenses from those acquired terminals, an increase of $6.1 million in blending fees and a $2.8 million customer settlement, partially offset by increased salaries, wages and incentive compensation expenses due to our expanded operations. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue was $119.2 million for the year ended December 31, 2008, which is an increase of $15.4 million or 14.8% from the corresponding period in 2007. This overall increase resulted primarily from (i) $6.5 million of incremental revenue in 2008 from the acquisitions of the Niles, Michigan, Ferrysburg, Michigan, Wethersfield, Connecticut, and Albany, New York terminals in 2008, combined with the effect of having a full year of revenue in 2008 from the six terminals that were acquired in the first quarter of 2007; (ii) $6.1 million of revenue related to increases in blending fees for product additives and product recoveries from vapor recovery units, which were offset by an approximately 5.4% decline in throughput volumes, caused in part by increased commodity prices, in 2008 compared to 2007; and (iii) $2.8 million from the settlement of a dispute with a customer regarding product handling charges.

Total costs and expenses were $65.5 million for the year ended December 31, 2008, which is an increase of $4.5 million or 7.4% from the corresponding period in 2007. Total costs and expenses include depreciation and amortization which is not a component of Adjusted EBITDA. The increase in total costs and expenses is primarily due to an increase of $2.1 million in operating expenses for the terminal acquisitions made at various times in 2007 and 2008 and an increase of $1.6 million in payroll and payroll benefits in 2008 resulting primarily from an increase in the number of employees due to our expanded operations, partially offset by a decrease of $1.2 million in terminal additive expense related to decreased throughput volumes at our terminals.

Operating income was $53.7 million for the year ended December 31, 2008 compared to operating income of $42.8 million for the year ended December 31, 2007. Depreciation and amortization of $6.6 million increased during the year ended December 31, 2008 by $1.0 million from $5.6 million for the year ended December 31, 2007 as a result of terminals acquired at various times in 2008 and 2007. Other revenue and expense items impacting operating income are discussed above.

Natural Gas Storage

Adjusted EBITDA from the Natural Gas Storage segment was $42.4 million for the year ended December 31, 2008. Revenue and expenses affecting Adjusted EBITDA are more fully discussed below.

Revenue was $61.8 million for the year ended December 31, 2008. Approximately 70.2% of this revenue represented lease storage revenues and 29.8% represented hub services revenues. All of this revenue was derived from Lodi Gas operations, which we acquired on January 18, 2008.

Total costs and expenses were $29.1 million for the year ended December 31, 2008. Costs and expenses were from Lodi Gas legacy operations, which we acquired on January 18, 2008, and included $5.0 million of depreciation and amortization and $4.6 million of non-cash deferred lease expense, which are not components of Adjusted EBITDA. The Natural Gas Storage segment incurred $4.1 million of payroll and payroll benefits expense, $4.2 million of outside services costs, of which $3.2 million related to well work-over costs, $2.4 million of property and other taxes, $2.7 million of rental expense, $0.9 million of insurance costs and $3.6 million of other costs in 2008.

Operating income was $32.7 million for the year ended December 31, 2008. Depreciation and amortization was $5.0 million for the year ended December 31, 2008. Other revenue and expense items impacting operating income are discussed above.

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Energy Services

Adjusted EBITDA from the Energy Services segment was $9.8 million for the year ended December 31, 2008. Revenue and expenses affecting Adjusted EBITDA are more fully discussed below.

Revenue was $1,295.9 million for the year ended December 31, 2008. Substantially all of this revenue was derived from Farm & Home s legacy wholesale operations, which we acquired on February 8, 2008. During 2008, approximately 435.2 million gallons of products were sold. Products sold include gasoline, propane and petroleum distillates such as heating oil, diesel fuel and kerosene.

Total costs and expenses were $1,289.9 million for the year ended December 31, 2008 and included $3.7 million of depreciation and amortization, which is not a component of Adjusted EBITDA. Substantially all of these costs and expenses were derived from Farm & Home s legacy wholesale operations. Approximately $1,269.6 million was attributable to products sold by the Energy Services segment. Additionally, the Energy Services segment incurred $7.3 million of payroll and payroll benefits expense, $1.1 million of outside service costs, $0.7 million of property and other taxes, $0.6 million of rental expense, $0.4 million of insurance costs and $6.8 million of other costs in 2008.

Operating income was $6.0 million for the year ended December 31, 2008. Depreciation and amortization was $3.7 million for the year ended December 31, 2008. Other revenue and expense items impacting operating income are discussed above.

Development and Logistics

Adjusted EBITDA from the Development and Logistics segment of $8.8 million decreased during the year ended December 31, 2008 by $0.8 million or 8.0% from $9.5 million during the year ended December 31, 2007. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue was $43.5 million for the year ended December 31, 2008, which is an increase of $7.3 million or 20.1% from the corresponding period in 2007. The increase in revenues in 2008 was primarily the result of an increase of $7.0 million in construction management revenue related to construction contracts that were substantially completed at December 31, 2008. These construction activities are principally conducted on a time and material basis.

Total costs and expenses were $35.6 million for the year ended December 31, 2008, which is an increase of $8.3 million or 30.4% from the corresponding period in 2007. Total costs and expenses include depreciation and amortization which is not a component of Adjusted EBITDA. The increase in total costs and expenses is associated with increased construction contract activity. Construction management costs were $12.6 million in 2008, which is an increase of $5.3 million over 2007. The increase in 2008 was primarily the result of an increase in construction contracts that were substantially completed at December 31, 2008. Additionally, outside services costs increased $2.4 million and payroll and payroll benefits expense increased approximately $0.7 million due to the increased construction activities.

Operating income was $7.9 million for the year ended December 31, 2008 compared to operating income of $8.9 million for the year ended December 31, 2007. Depreciation and amortization was $1.8 million for the year ended December 31, 2008, which is an increase of $0.2 million from the corresponding period in 2007. Income tax expense of $0.8 million was consistent with the same period in 2007. Other revenue and expense items impacting operating income are discussed above.

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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 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.

We continue to evaluate the conditions of the debt and equity capital markets, and in March 2009, we issued 2.6 million LP Units in an underwritten public offering at $35.08 per LP Unit. On April 29, 2009, the underwriters of the equity offering exercised their option to purchase an additional 390,000 LP Units at $35.08 per LP Unit. Total proceeds from the offering, including the overallotment option and after the underwriter s discount of $1.17 per LP Unit and offering expenses, were approximately $104.6 million, and were used to reduce amounts outstanding under our Credit Facility. In August 2009, we sold 5.500% Notes in an underwritten public offering. The 5.500% Notes were issued at 99.35% of their principal amount. Total proceeds from the offering, after underwriters fees, expenses and debt issuance costs of $1.8 million, were approximately $271.4 million, and were used to reduce amounts outstanding under the Credit Facility and for general partnership purposes.

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 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 December 31, 2009, we had $34.6 million of cash and cash equivalents on hand and approximately $401.9 million of available credit under the Credit Facility, after application of the facility s funded debt ratio covenant. In addition, BES had $10.2 million of available credit under the BES Credit Agreement, pursuant to certain borrowing base calculations under that agreement. See Note 13 in the Notes to Consolidated Financial Statements for further information about our credit facilities.

At December 31, 2009, we had an aggregate face amount of $1,742.8 million of debt, which consisted of the following:

- $300.0 million of the 4.625% Notes due 2013 (the 4.625% Notes);
- $275.0 million of the 5.300% Notes due 2014 (the 5.300% Notes);
- $125.0 million of the 5.125% Notes due 2017 (the 5.125% Notes);
- $300.0 million of the 6.050% Notes due 2018 (the 6.050% Notes);
- $275.0 million of the 5.500% Notes due 2019;
- $150.0 million of the 6.750% Notes due 2033 (the 6.750% Notes);
- $78.0 million outstanding under our Credit Facility; and
- $239.8 million outstanding under the BES Credit Agreement.

See Note 13 in the Notes to 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 $1,762.1 million and $1,367.7 million at December 31, 2009 and 2008, respectively. The fair values of the fixed-rate debt at December 31, 2009 and 2008 were estimated by market-observed 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 rate.

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

Credit Ratings

Our debt securities are rated BBB by Standard & Poor s Ratings Service and Baa2 by Moody s Investors Service, Inc., both with stable outlooks. Such ratings reflect only the view of the rating agency and should not be interpreted as a recommendation to buy, sell or hold our securities. These ratings may be revised or withdrawn at any time by the agencies at their discretion and should be evaluated independently of any other rating.

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):

	Year Ended December 31,		
	2009	**2008**	**2007**
Cash provided by (used in):			
Continuing operating activities	$ 56,183	$ 214,962	$ 197,487
Operating activities	56,183	215,254	197,487
Investing activities	(144,203)	(735,776)	(108,605)
Financing activities	63,776	486,167	(14,630)

Operating Activities

2009 Compared to 2008. Net cash flow provided by operating activities was $56.2 million for the year ended December 31, 2009 compared to $215.3 million for the year ended December 31, 2008. The following were the principal factors resulting in the $159.1 million decrease in net cash flows provided by operating activities:

- We recognized $32.1 million of reorganization expenses in the 2009 period.

- The net change in fair values of derivatives was an increase of $20.5 million, resulting from the decrease 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 a decrease of $227.9 million to cash flows from operating activities for the year ended December 31, 2009. The principal factors affecting the working capital changes were:

  - Inventories increased $177.3 million due to an increase in inventory purchases within the Energy Services segment which are hedged with futures contracts that expire primarily in the winter months. As a result of energy market conditions, we significantly increased our physical inventory purchases in 2009.

  - Trade receivables increased $44.1 million primarily due to increased activity from our Energy Services segment due to higher volumes in the 2009 period.

  - Prepaid and other current assets increased $31.6 million primarily due to increases in prepaid services and unbilled revenue within the Natural Gas Storage segment and an increase in receivables due to a favorable property tax settlement, partially offset by a decrease in a receivable related to ammonia purchases and a decrease in margin deposits on futures contracts in our Energy Services segment.

Accrued and other current liabilities increased $2.6 million primarily due to costs related to the reorganization.

Accounts payable increased $15.2 million due to activity within the Energy Services segment.

Construction and pipeline relocation receivables decreased $7.4 million primarily due to a decrease in construction activity in the 2009 period.

2008 Compared to 2007. Net cash flow provided by operating activities was $215.3 million for the year ended December 31, 2008 compared to $197.5 million for the year ended December 31, 2007. The following were the principal factors resulting in the $17.8 million increase in net cash flows provided by operating activities:

Our income from continuing operations increased $28.0 million for the year ended December 31, 2008 compared with the year ended December 31 2007, primarily due to our acquisitions of Lodi Gas and Farm & Home in 2008.

The net change in fair values of derivatives was a decrease of $24.2 million, 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. We did not utilize futures contracts to economically hedge a portion of the fixed-price sales contracts because we had purchased inventory to fulfill a portion of those commitments.

The net impact of working capital changes was a decrease of $8.9 million to cash flows from operations for the year ended December 31, 2008. The principal factors affecting the working capital changes were:

Prepaid and other current assets increased $25.7 million, primarily due to an increase in a receivable related to ammonia purchases as well as additional margin deposits associated with liabilities for derivative instruments.

Construction and pipeline relocation receivables increased $8.9 million due to an increase in construction activity in the latter part of 2008.

Inventories increased $4.4 million due to inventory purchases within the Energy Services segment.

Accounts payable decreased $10.9 million due to activity within the Energy Services segment since the acquisition of Farm & Home.

Trade receivables decreased $36.1 million due to an increase in collections within the Energy Services segment since the acquisition of Farm & Home.

Accrued and other current liabilities increased $4.9 million primarily due to increases in accrued taxes, environmental liabilities and interest expense.

Investing Activities

2009 Compared to 2008. Net cash flow used in investing activities was $144.2 million for the year ended December 31, 2009 compared to $735.8 million for the year ended December 31, 2008. The following were the principal factors resulting in the $591.6 million decrease in net cash flows used in investing activities:

Cash used for acquisitions and equity investments, net of cash acquired, was $58.3 million for the year ended December 31, 2009, of which $54.4 million was used for the acquisition of refined petroleum product terminals and pipeline assets from ConocoPhillips. We also invested an additional $3.9 million in WT LPG in 2009. Cash used for acquisitions and equity investments, net of cash acquired, was $667.5 million for the year ended December 31, 2008, of which $438.8 million was used for the acquisition of Lodi Gas, $143.3 million was used for the acquisition of Farm & Home and an aggregate of $75.6 million was used for the acquisitions of four terminals in Albany, New York, Niles and Ferrysburg, Michigan, and Wethersfield, Connecticut and the acquisition of the remaining 50% member interest in Wespac San Diego that we did not already own. We also invested an additional $9.8 million in WT LPG in 2008. See Note 4 in the Notes to

Consolidated Financial Statements for further information.

Capital expenditures decreased $33.2 million for the year ended December 31, 2009 compared with the year ended December 31, 2008. See below for a discussion of capital spending.

Cash proceeds from the sale of discontinued operations were $52.6 million for the year ended December 31, 2008, which related to the sale of the retail operations of Farm & Home.

2008 Compared to 2007. Net cash flow used in investing activities was $735.8 million for the year ended December 31, 2008 compared to $108.6 million for the year ended December 31, 2007. The following were the principal factors resulting in the $627.2 million increase in net cash flows used in investing activities:

Cash used for acquisitions and equity investments, net of cash acquired was $667.5 million for the year ended December 31, 2008 as discussed above. Cash used for acquisitions and equity investments, net of cash acquired was $40.7 million for the year ended December 31, 2007, of which $39.8 million was used for the acquisition of terminals and related assets and $0.9 million was used for an additional investment in WT LPG. See Note 4 in the Notes to Consolidated Financial Statements for further information.

Capital expenditures increased $52.6 million for the year ended December 31, 2008 compared with the year ended December 31, 2007. See below for a discussion of capital spending.

Cash proceeds from the sale of discontinued operations were $52.6 million for the year ended December 31, 2008, which related to the sale of the retail operations of Farm & Home.

Capital expenditures are summarized below (net of non-cash changes in accruals for capital expenditures for the years ended December 31, 2009, 2008 and 2007) for the periods indicated (in thousands):

	Year Ended December 31,		
	2009	**2008**	**2007**
Sustaining capital expenditures	$ 23,496	$ 28,936	$ 33,838
Expansion and cost reduction	63,813	91,536	34,029
Total capital expenditures	$ 87,309	$ 120,472	$ 67,867

In 2009 and 2008, expansion and cost reduction projects included the Kirby Hills Phase II expansion project, ethanol and butane blending projects at certain of our terminals, 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. Construction costs of the Kirby Hills Phase II expansion project in 2009 and 2008 totaled approximately $17.0 million and $49.6 million, respectively. In 2007, expansion and cost reduction projects included a capacity expansion project in Illinois to handle additional liquefied petroleum gas volumes and ongoing capacity improvements at facilities to serve the Memphis International Airport.

We expect to spend approximately $90.0 million to $110.0 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 $65.0 million to $75.0 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, the construction of a 4.4 mile pipeline in central Connecticut to connect our pipeline in Connecticut to a third party electric generation plant currently under construction, various terminal expansions and upgrades and pipeline and terminal automation projects.

Financing Activities

2009 Compared to 2008. Net cash flow provided by financing activities was $63.8 million for the year ended December 31, 2009 compared to $486.2 million for the year ended December 31, 2008. The following were the principal factors resulting in the $422.4 million decrease in net cash flows provided by financing activities:

We borrowed $317.1 million and $558.6 million and repaid $537.4 million and $260.3 million under the Credit Facility in 2009 and 2008, respectively.

Net borrowings under the BES Credit Agreement were $143.8 million in 2009, while net repayments under the BES Credit Agreement (and its predecessor facility which was replaced in May 2008) were $4.0 million in 2008.

We received $271.4 million (net of debt issuance costs of $1.8 million) from the issuance in August 2009 of $275.0 million in aggregate principal amount of the 5.500% Notes in an underwritten public offering. Proceeds from this offering were used to reduce amounts outstanding under the Credit Facility. We received $298.0 million from the issuance in January 2008 of $300.0 million in aggregate principal amount of the 6.050% Notes in an underwritten public offering. Proceeds from this offering were used to partially pre-fund the Lodi Gas acquisition. In connection with this debt offering, we settled two interest rate swaps associated with the 6.050% Notes, which resulted in a settlement payment of $9.6 million that is being amortized as interest expense over the ten-year term of the 6.050% Notes.

We received $104.6 million in net proceeds from an underwritten equity offering in March 2009 from the public issuance of 3.0 million LP Units. In 2008, we received $113.1 million in net proceeds from the public issuance of 2.6 million LP Units.

Cash distributions paid to our partners increased $27.0 million year-to-year 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 $230.4 million ($3.63 per LP Unit) and $203.2 million ($3.43 per LP Unit) during the years ended December 31, 2009 and 2008, respectively.

2008 Compared to 2007. Net cash flow provided by financing activities was $486.2 million for the year ended December 31, 2008 compared to net cash used in financing activities of $14.6 million for the year ended December 31, 2007. The following were the principal factors resulting in the $500.8 million increase in net cash flows provided by financing activities:

We borrowed $558.6 million and $155.0 million and repaid $260.3 million and $300.0 million under the Credit Facility (and its predecessor facility) in 2008 and 2007, respectively.

Net repayments under the BES Credit Agreement (and its predecessor facility which was replaced in May 2008) were $4.0 million in 2008.

We received $298.1 million from the issuance in January 2008 of $300.0 million in aggregate principal amount of the 6.050% Notes in an underwritten public offering as discussed above.

We received $113.1 million in net proceeds from an underwritten equity offering in March 2008 from the public issuance of 2.6 million LP Units. In 2007, we received $296.4 million in net proceeds from underwritten equity offerings in March, August and December 2007 from the public issuance of 6.2 million LP Units.

Cash distributions paid to our partners increased $38.8 million year-to-year 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 $203.2 million ($3.43 per LP Unit) and $164.3 million ($3.23 per LP Unit) during the years ended December 31, 2008 and 2007, respectively.

Derivatives

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk Market Risk Non Trading Instruments for a discussion of commodity derivatives used by our Energy Services segment.

Critical Accounting Policies

The preparation of consolidated financial statements in conformity with GAAP requires management to select appropriate accounting principles from those available, to apply those principles consistently and to make reasonable estimates and assumptions that affect revenues and associated costs as well as reported amounts of assets and liabilities. The following describes the estimated risks underlying our critical accounting policies and estimates:

Depreciation Methods, Estimated Useful Lives and Disposals of Property, Plant and Equipment

In general, depreciation is the systematic and rational allocation of an asset s cost or fair value, less its residual value (if any), to the periods it benefits. Property, plant and equipment consist primarily of pipelines, wells, storage and terminal facilities, pad gas and pumping and compression equipment. Depreciation on pipelines and terminals is generally calculated using the straight-line method over the estimated useful lives ranging from 44 to 50 years. Plant and equipment associated with our natural gas storage business is generally depreciated over 44 years, except for pad gas. The Natural Gas Storage segment maintains a level of natural gas in its underground storage facility generally known as pad gas, which is not routinely cycled but, instead, serves the function of maintaining the necessary pressure to allow routine injection and withdrawal to meet demand. Pad gas is considered to be a component of the facility and as such is not depreciated because it is expected to ultimately be recovered and sold. Other plant and equipment is generally depreciated on a straight-line basis over an estimated life of 5 to 50 years. Straight line depreciation results in depreciation expense being incurred evenly over the life of an asset.

Additions to property, plant and equipment, including major replacements or betterments, are recorded at cost. We charge maintenance and repairs to expense in the period incurred. The cost of property, plant and equipment sold or retired and the related depreciation, except for certain pipeline system assets, are removed from our consolidated balance sheet in the period of sale or disposition, and any resulting gain or loss is included in income. For our pipeline system assets, we generally charge the original cost of property sold or retired to accumulated depreciation and amortization, net of salvage and cost of removal. When a separately identifiable group of assets, such as a stand-alone pipeline system, is sold, we will recognize a gain or loss in our consolidated statements of operations for the difference between the cash received and the net book value of the assets sold.

The determination of an asset s useful life requires assumptions regarding a number of factors including technological change, normal depreciation and actual physical usage. If any of these assumptions subsequently change, the estimated useful life of the asset could change and result in an increase or decrease in depreciation expense that could have a material impact on our consolidated financial statements.

At both December 31, 2009 and 2008, the net book value of our property, plant and equipment was $2.2 billion. Property, plant and equipment is generally recorded at its original acquisition cost and its carrying value accounted for approximately 68.4% of our consolidated assets at December 31, 2009. Depreciation expense was $50.7 million, $47.2 million and $39.4 million for the years ended December 31, 2009, 2008 and 2007, respectively. We do not believe that there is a reasonable likelihood that there will be a material change in the future estimated useful life of our property, plant and equipment. In the past, we have generally not deemed it necessary to materially change the depreciable lives of our assets. An increase or decrease in the depreciable lives of these assets, for example a 5-year increase or decrease in the depreciable lives of our pipeline assets, currently estimated as 50 years, would decrease or increase, respectively, annual depreciation expense, and increase or decrease operating income, respectively, by approximately $5.0 million annually.

Reserves for Environmental Matters

We are subject to federal, state and local laws and regulations relating to the protection of the environment. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to existing conditions caused by past operations, and which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated based upon past experience and advice of outside engineering, consulting and law firms. Generally, the timing of these accruals coincides with our commitment to a formal plan of action. Accrued environmental remediation related expenses include estimates of direct costs of remediation and indirect costs related to the remediation effort, such as compensation and benefits for employees directly involved in the remediation activities and fees paid to outside engineering, consulting and law firms. Historically, our estimates of direct and indirect costs related to remediation efforts have generally not required material adjustments. However, the accounting estimates related to environmental matters are uncertain because (1) estimated future expenditures related to environmental matters are subject to cost fluctuations and can change materially, (2) unanticipated liabilities may arise in connection with environmental remediation projects and may impact cost estimates, and (3) changes in federal, state and local environmental laws and regulations can significantly increase the cost or potential liabilities related to environmental matters. None of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable. We maintain insurance that may cover certain environmental expenditures.

During the years ended December 31, 2009, 2008 and 2007, we incurred environmental expenses, net of insurance recoveries, of $10.6 million, $10.1 million and $7.4 million, respectively. At December 31, 2009 and 2008, we had accrued $29.9 million and $27.0 million, respectively, for environmental matters. The environmental

accruals are revised as new matters arise, or as new facts in connection with environmental remediation projects require a revision of estimates previously made with respect to the probable cost of such remediation projects. Changes in estimates of environmental remediation for each remediation project will affect operating income on a dollar-for-dollar basis up to our self-insurance limit. Our self-insurance limit is currently $3.0 million per occurrence.

Fair Value of 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 contracts. See Note 8 in the Notes to Consolidated Financial Statements for further discussion. The Energy Services segment has not used hedge accounting with respect to its fixed-price sales contracts. Therefore, its fixed-price sales contracts and the related futures contracts used to offset those fixed-price sales contracts are all marked-to-market on our balance sheet with gains and losses being recognized in earnings during the period. At December 31, 2009, we included in our consolidated financial statements as assets fixed-price sales contracts with asset values of approximately $2.4 million. We have entered into futures contracts to hedge against changes in value of these fixed price sales contracts. These futures contracts have a net value of approximately $7.1 million at December 31, 2009 and have been recognized as assets on our balance sheet. We have determined that the exchange-traded futures contracts represent Level 1 fair value measurements because the prices for such futures contracts are established on liquid exchanges with willing buyers and sellers and with prices which are readily available on a daily basis.

We have determined that the fixed-price sales contracts represent Level 2 fair value measurements because their value is derived from similar contracts for similar delivery and settlement terms which are traded on established exchanges. However, because the fixed-price sales contracts are privately negotiated with customers of the Energy Services segment who are generally smaller, private companies that may not have established credit ratings, the determination of an adjustment to fair value to reflect counterparty credit risk (a credit valuation adjustment) requires significant management judgment. At December 31, 2009, we had reduced the fair value of the fixed-price sales contracts by a $0.9 million credit valuation adjustment to reflect this counterparty credit risk. The delivery periods for the contracts range from one to 13 months, with the substantial majority of deliveries concentrated in the first four months of 2010.

Because little or no public credit information is available for the Energy Services segment s customers who have fixed-price sales contracts, we specifically analyzed each customer and contract to evaluate (i) the historical payment patterns of the customer, (ii) the current outstanding receivables balances for each customer and contract and (iii) the level of performance of each customer with respect to volumes called for in the contract. We then evaluated the specific risks and expected outcomes of nonpayment or nonperformance by each customer and contract. Based on our credit and performance risk evaluation, we recorded the credit valuation adjustment of $0.9 million. If actual customer performance under these fixed-price sales contracts deteriorates (either through nonperformance with respect to contracted volumes or nonpayment of amounts due), then the fair value of these contracts could be materially less. For example, a 10% shortfall in delivered volumes over the average life of the contracts would reduce the fair value of the contracts and, accordingly, net income, by $0.2 million. We continue to monitor and evaluate performance and collections with respect to these fixed-price sales contracts.

Measuring the Fair Value of Goodwill

Goodwill represents the excess of purchase prices paid by us in certain business combinations over the fair values assigned to the respective net tangible and identifiable intangible assets. We do not amortize goodwill; rather, we test our goodwill (at the reporting unit level) for impairment on January 1 of each fiscal year, and more frequently if circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. A reporting unit is a business segment or one level below a business segment for which discrete financial information is available and regularly reviewed by segment management. Our reporting units are our business segments. An estimate of the fair value of a reporting unit is determined using a combination of a market multiple valuation method and an expected present value of future cash flows valuation method. The principal assumptions utilized in this valuation model include: (1) discrete financial forecasts for the assets contained within the reporting unit, which rely on management s estimates of revenue, operating expenses and volumes; (2) long-term growth rates for cash

flows beyond the discrete forecast period; (3) appropriate discount rates; and (4) determination of appropriate market multiples from comparable companies.

If the fair value of the reporting unit (including its inherent goodwill) is less than its carrying value, a charge to earnings is required to reduce the carrying value of the goodwill to its implied fair value. At December 31, 2009 and 2008, the carrying value of our goodwill was $208.9 million and $210.6 million, respectively. Goodwill decreased by $1.8 million as of December 31, 2009 from December 31, 2008 due to the finalization of the purchase price allocation relating to the acquisition of a terminal in Albany, New York in 2008; this $1.8 million was allocated to property, plant and equipment. We did not record any goodwill impairment charges during the years ended December 31, 2009, 2008 and 2007. A 10% decrease in the estimated fair value of any of our reporting units would have had no impact on the carrying value of goodwill at the annual measurement date.

Measuring Recoverability of Long-Lived Assets and Equity Method Investments

In general, long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Such events or changes include, among other factors: operating losses, unused capacity; market value declines; technological developments resulting in obsolescence; changes in demand for products in a market area; changes in competition and competitive practices; and changes in governmental regulations or actions. Recoverability of the carrying amount of assets to be held and used is measured by a comparison of the carrying amount of the asset to estimated future undiscounted net cash flows expected to be generated by the asset. Estimates of future undiscounted net cash flows include anticipated future revenues, expected future operating costs and other estimates. Such estimates of future undiscounted net cash flows are highly subjective and are based on numerous assumptions about future operations and market conditions. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the estimated fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or estimated fair value less costs to sell. We recorded an impairment of $59.7 million during the year ended December 31, 2009 related to an impairment of Buckeye NGL. A significant loss in the customer base utilizing Buckeye s NGL pipeline, in conjunction with the authorization by the Board of Directors of Buckeye GP to pursue the sale of Buckeye NGL, triggered an evaluation of a potential asset impairment that resulted in a non-cash charge to earnings of $72.5 million in the Pipeline Operations segment in the second quarter of 2009. Effective January 1, 2010, we sold our ownership interest in Buckeye NGL for $22.0 million. The sales proceeds exceeded the previously impaired carrying value of the assets of Buckeye NGL by $12.8 million resulting in the reversal of $12.8 million of the previously recorded asset impairment expense in the fourth quarter of 2009. See Note 8 in the Notes to Consolidated Financial Statements for further discussion.

An equity method investment is evaluated for impairment whenever events or changes in circumstances indicate that there is a possible other than temporary loss in value of the investment. Examples of such events include sustained operating losses of the investee or long-term negative changes in the investee s industry. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flow expected to be derived from the investment. This estimate of discounted cash flows is based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment. A significant change in these underlying assumptions could result in our recording an impairment charge.

Other Considerations

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2009 (in thousands):

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt (1)	$ 1,503,000	$	$ 78,000	$ 575,000	$ 850,000
Interest payments (2)	709,646	78,256	156,512	133,139	341,739
Operating leases: (3)					
Office space and other	18,978	1,528	3,075	3,178	11,197
Land leases (4)	311,747	2,945	6,341	6,951	295,510
Purchase obligations (5)	32,480	32,480			
Capital expenditure obligations (6)	1,611	1,611			
Total	$ 2,577,462	$ 116,820	$ 243,928	$ 718,268	$ 1,498,446

(1) We have long-term payment obligations under our Credit Facility and our underwritten publicly issued notes. Amounts shown in the table represent our scheduled future maturities of long-term debt principal for the periods indicated. We have assumed that the borrowings under our Credit Facility as of December 31, 2009 will not be repaid until the maturity date of the facility. See Note 13 in the

Notes to Consolidated Financial Statements for additional information regarding our debt obligations.

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

(3) We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the table represent minimum lease payment obligations under our operating leases with terms in

excess of one year for the periods indicated. Lease expense is charged to operating expenses on a straight line basis over the period of expected benefit. Contingent rental payments are expensed as incurred. Total rental expense for the years ended December 31, 2009, 2008 and 2007 was $21.2 million, $20.2 million and $11.7 million, respectively.

(4) We have leases for subsurface underground gas storage rights and surface rights in connection with our operations in the Natural Gas Storage segment. We may cancel these leases if the storage reservoir is not used for underground storage of natural gas or the removal or injection thereof for a continuous

period of two consecutive years. Lease expense associated with these leases is being recognized on a straight line basis over 44 years. For the year ended December 31, 2009, the Natural Gas Storage segment s lease expense was $7.4 million, including $4.5 million recorded as an increase in our deferred lease liability. We estimate that the deferred lease liability will continue to increase through 2032, at which time our deferred lease liability is estimated to be approximately $64.7 million. Our deferred lease liability will then be reduced over the remaining 19 years of the lease, since the expected annual lease payments will exceed the amount of lease expense.

(5)

We have long and short-term purchase obligations for products and services with third-party suppliers. The prices that we are obligated to pay under these contracts approximate current market prices. The table shows our commitments and estimated payment obligations under these contracts for the periods indicated. Our estimated future payment obligations are based on the contractual price under each contract for products and services at December 31, 2009.

(6) We have short-term payment obligations relating to capital projects we have initiated. These commitments represent unconditional payment obligations that we have agreed to pay vendors

for services
rendered or
products
purchased.

In addition, our obligations related to our pension and postretirement benefit plans are discussed in Note 17 in the Notes to Consolidated Financial Statements.

Employee Stock Ownership Plan

Services Company provides an employee stock ownership plan (the ESOP) to the majority of its employees hired before September 16, 2004. Employees hired by Services Company after September 15, 2004, and certain employees covered by a union multiemployer pension plan do not participate in the ESOP. The ESOP owns all of the outstanding common stock of Services Company.

At December 31, 2009, the ESOP was directly obligated to a third-party lender for $7.7 million with respect to the 3.60% Notes due 2011 (the 3.60% ESOP Notes). The 3.60% ESOP Notes were issued on May 4, 2004 to refinance Services Company s 7.24% ESOP Notes which were originally issued to purchase Services Company common stock. The 3.60% ESOP Notes are collateralized by Services Company common stock and are guaranteed by Services Company. We have committed that, in the event that the value of our LP Units owned by Services Company falls to less than 125% of the balance payable under the 3.60% ESOP Notes, we will fund an escrow account with sufficient assets to bring the value of the total collateral (the value of LP Units owned by Services Company and the escrow account) up to the 125% minimum. Amounts deposited in the escrow account are returned to us when the value of the LP Units owned by Services Company returns to an amount which exceeds the 125% minimum. At December 31, 2009, the value of the LP Units owned by Services Company was approximately $89.3 million, which exceeded the 125% requirement.

Services Company stock is released to employee accounts in the proportion that current payments of principal and interest on the 3.60% ESOP Notes bear to the total of all principal and interest payments due under the 3.60% ESOP Notes. Individual employees are allocated shares based upon the ratio of their eligible compensation to total eligible compensation. See Note 19 in the Notes to Consolidated Financial Statements for further information.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements except for operating leases and outstanding letters of credit (see Note 13 in the Notes to Consolidated Financial Statements).

Related Party Transactions

With respect to related party transactions, see Note 20 in the Notes to Consolidated Financial Statements and Item 13, Certain Relationships and Related Transactions and Director Independence.

Recent Accounting Pronouncements

See Note 2 in the Notes to Consolidated Financial Statements for a description of certain new accounting pronouncements that will or may affect our consolidated financial statements.

Item 7A. 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.

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Commodity Risk

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 NYMEX futures contracts to the change in fair value of our hedged fuel inventory.

The Energy Services segment has not used hedge accounting with respect to its fixed-price sales contracts. Therefore, its fixed-price sales contracts and the related futures contracts used to offset those fixed-price sales contracts are all marked-to-market on the balance sheet with gains and losses being recognized in earnings during each reporting period.

As of December 31, 2009, the Energy Services segment had derivative assets and liabilities as follows (in thousands):

		December 31, 2009
Assets:		
Fixed-price sales contracts	$	4,959
Liabilities:		
Fixed-price sales contracts		(3,662)
Futures contracts for inventory and fixed-price sales contracts		(11,003)
Total	$	(9,706)

Substantially all of the unrealized loss at December 31, 2009 for inventory hedges represented by futures contracts will be realized by the second quarter of 2010 as the related inventory is sold. Gains recorded on inventory hedges that were ineffective were approximately $2.6 million for the year ended December 31, 2009. As of December 31, 2009, 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 December 2010. In addition, at December 31, 2009, we had refined petroleum product inventories which we intend to use to satisfy a portion of the fixed-price sales contracts.

Based on a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at December 31, 2009, 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)	Liability	$ (9,706)
Fair value assuming 10% increase in underlying commodity prices	Liability	$(40,642)
Fair value assuming 10% decrease in underlying commodity prices	Asset	$ 21,223

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.

Interest Rate Risk

We manage a portion of our interest rate exposure by utilizing interest rate swaps to effectively convert a portion of our variable-rate debt into fixed-rate debt. In addition, 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, 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 an existing debt obligation.

At December 31, 2009, 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 6.75% Notes, $300.0 million of the 6.05% Notes and $275.0 million of the 5.500% Notes. The fair value of these fixed-rate debt obligations at December 31, 2009 was approximately $1,444.3 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 $88.4 million. Our variable-rate obligation was $78.0 million under the Credit Facility and $239.8 million under the BES Credit Agreement at December 31, 2009. Based on the balances outstanding at December 31, 2009, a hypothetical 100 basis point increase or decrease in interest rates would increase or decrease annual interest expense by $3.2 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. 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. Unrealized gains of $17.2 million were recorded in accumulated other comprehensive loss to reflect the change in the fair values of the forward-starting interest rate swaps as of December 31, 2009. 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.

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The following table presents the effect of hypothetical price movements on the estimated fair value of our interest rate swap portfolio and the related change in fair value of the underlying debt at December 31, 2009 (in thousands):

Scenario	Resulting Classification	Financial Instrument Portfolio Fair Value
Fair value assuming no change in underlying interest rates (as is)	Asset	$17,204
Fair value assuming 10% increase in underlying interest rates	Asset	$26,886
Fair value assuming 10% decrease in underlying interest rates	Asset	$ 667

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

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MANAGEMENT S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Buckeye GP LLC (Buckeye GP), as general partner of Buckeye Partners, L.P. (Buckeye), is responsible for establishing and maintaining adequate internal control over financial reporting of Buckeye. Internal control over financial reporting is a process designed to provide reasonable, but not absolute, assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. A company s internal control over financial reporting includes those policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

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

Management evaluated Buckeye GP s internal control over financial reporting of Buckeye as of December 31, 2009. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework* (COSO). As a result of this assessment and based on the criteria in the COSO framework, management has concluded that, as of December 31, 2009, Buckeye GP s internal control over financial reporting of Buckeye was effective.

Buckeye s independent registered public accounting firm, Deloitte & Touche LLP, has audited Buckeye GP s internal control over financial reporting for Buckeye. Their opinion on the effectiveness of Buckeye GP s internal control over financial reporting for Buckeye appears herein.

/s/ FORREST E. WYLIE	/s/ KEITH E. ST.CLAIR
Forrest E. Wylie	Keith E. St.Clair
Chief Executive Officer	Chief Financial Officer
February 26, 2010	

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of Buckeye Partners, L.P.

We have audited the internal control over financial reporting of Buckeye Partners, L.P. and subsidiaries (Buckeye) as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Buckeye s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on Buckeye s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Buckeye maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2009 of Buckeye and our report dated February 26, 2010 expressed an unqualified opinion on those consolidated financial statements and included an explanatory paragraph regarding Buckeye s change in its method of accounting for noncontrolling interests in 2009.

/s/ DELOITTE & TOUCHE LLP
Philadelphia, Pennsylvania
February 26, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of Buckeye Partners, L.P.

We have audited the accompanying consolidated balance sheets of Buckeye Partners, L.P. and subsidiaries (Buckeye) as of December 31, 2009 and 2008, and the related consolidated statements of operations, comprehensive income, cash flows, and partners capital (deficit) for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of Buckeye s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Buckeye Partners, L.P. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, Buckeye changed its method of accounting for noncontrolling interests in 2009.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Buckeye s internal control over financial reporting as of December 31, 2009, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2010 expressed an unqualified opinion on Buckeye s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Philadelphia, Pennsylvania
February 26, 2010

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

	Year Ended December 31,		
	2009	**2008**	**2007**
Revenues:			
Product sales	$ 1,125,653	$ 1,304,097	$ 10,680
Transportation and other services	644,719	592,555	508,667
Total revenue	1,770,372	1,896,652	519,347
Costs and expenses:			
Cost of product sales and natural gas storage services	1,103,015	1,274,135	10,473
Operating expenses	273,985	279,454	240,258
Depreciation and amortization	59,164	55,299	44,651
Asset impairment expense	59,724		
General and administrative	33,984	34,143	21,885
Reorganization expense	32,057		
Total costs and expenses	1,561,929	1,643,031	317,267
Operating income	208,443	253,621	202,080
Other income (expense):			
Earnings from equity investments	12,531	7,988	7,553
Interest and debt expense	(74,851)	(74,387)	(50,378)
Other income	777	1,429	1,362
Total other expense	(61,543)	(64,970)	(41,463)
Income from continuing operations	146,900	188,651	160,617
Income from discontinued operations		1,230	
Net income	146,900	189,881	160,617
Less: net income attributable to noncontrolling interests	(5,918)	(5,492)	(5,261)
Net income attributable to Buckeye Partners, L.P.	$ 140,982	$ 184,389	$ 155,356
Amounts attributable to Buckeye Partners, L.P.:			
Income from continuing operations	$ 140,982	$ 183,159	$ 155,356
Income from discontinued operations		1,230	
Total amounts attributable to Buckeye Partners, L.P.	$ 140,982	$ 184,389	$ 155,356
Allocation of net income attributable to Buckeye Partners, L.P.:			
Net income allocated to general partner:			
Income from continuing operations	$ 55,153	$ 33,684	$ 27,796

Income from discontinued operations	$	$ 370	$
Net income allocated to limited partners:			
Income from continuing operations	$ 85,829	$ 149,475	$ 127,560
Income from discontinued operations	$	$ 860	$
Calculation of Earnings Per Limited Partner Unit:			
Earnings per limited partner unit-basic:			
Income from continuing operations	$ 1.84	$ 2.97	$ 2.91
Income from discontinued operations		0.03	
Earnings per limited partner unit-basic	$ 1.84	$ 3.00	$ 2.91
Earnings per limited partner unit-diluted:			
Income from continuing operations	$ 1.84	$ 2.97	$ 2.91
Income from discontinued operations		0.03	
Earnings per limited partner unit-diluted	$ 1.84	$ 3.00	$ 2.91
Weighted average number of limited partner units outstanding:			
Basic	50,620	47,747	42,051
Diluted	50,663	47,763	42,101

See Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2009	2008	2007
Net income	$ 146,900	$ 189,881	$ 160,617
Other comprehensive income (loss):			
Change in value of derivatives	17,722	(2,668)	(7,187)
Amortization of interest rate swaps	961	920	
Amortization of benefit plan costs	(1,640)	(2,573)	(1,929)
Adjustment to funded status of benefit plans	1,077	(5,477)	(838)
Total other comprehensive income (loss)	18,120	(9,798)	(9,954)
Comprehensive income	$ 165,020	$ 180,083	$ 150,663

See Notes to Consolidated Financial Statements.

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

	December 31, 2009	December 31, 2008
Assets:		
Current assets:		
Cash and cash equivalents	$ 34,599	$ 58,843
Trade receivables, net	124,165	79,969
Construction and pipeline relocation receivables	14,095	21,501
Inventories	310,214	84,229
Derivative assets	4,959	97,375
Assets held for sale	22,000	
Prepaid and other current assets	103,691	72,111
Total current assets	613,723	414,028
Property, plant and equipment, net	2,228,265	2,231,321
Equity investments	96,851	90,110
Goodwill	208,876	210,644
Intangible assets, net	45,157	44,114
Other non-current assets	62,777	44,193
Total assets	$ 3,255,649	$ 3,034,410
Liabilities and partners capital:		
Current liabilities:		
Line of credit	$ 239,800	$ 96,000
Accounts payable	56,525	41,301
Derivative liabilities	14,665	48,623
Accrued and other current liabilities	106,743	105,790
Total current liabilities	417,733	291,714
Long-term debt	1,498,970	1,445,722
Other non-current liabilities	102,851	100,702
Total liabilities	2,019,554	1,838,138
Commitments and contingent liabilities		
Partners capital:		
Buckeye Partners, L.P. unitholders capital (deficit):		
General Partner (243,914 units outstanding as of December 31, 2009 and 2008)	1,849	(6,680)
Limited Partners (51,438,265 and 48,372,346 units outstanding as of December 31, 2009 and 2008, respectively)	1,214,136	1,201,144
Accumulated other comprehensive loss	(847)	(18,967)

Total Buckeye Partners, L.P. unitholders capital	1,215,138	1,175,497
Noncontrolling interests	20,957	20,775
Total partners capital	1,236,095	1,196,272
Total liabilities and partners capital	$ 3,255,649	$ 3,034,410

See Notes to Consolidated Financial Statements.

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

	Year Ended December 31,		
	2009	**2008**	**2007**
Cash flows from operating activities:			
Net income	$ 146,900	$ 189,881	$ 160,617
Income from discontinued operations		(1,230)	
Income from continuing operations	146,900	188,651	160,617
Adjustments to reconcile income from continuing operations to net cash provided by continuing operations:			
Depreciation and amortization	59,164	55,299	44,651
Asset impairment expense	59,724		
Gain on the sale of assets			(828)
Net changes in fair value of derivatives	20,531	(24,228)	
Non-cash deferred lease expense	4,500	4,598	
Earnings from equity investments	(12,531)	(7,988)	(7,553)
Distributions from equity investments	9,660	5,113	7,418
Amortization of other non-cash items	6,931	3,216	428
Change in assets and liabilities, net of amounts related to acquisitions:			
Trade receivables	(44,112)	36,060	3,432
Construction and pipeline relocation receivables	7,406	(8,930)	(382)
Inventories	(177,309)	(4,362)	(863)
Prepaid and other current assets	(31,580)	(25,704)	1,154
Accounts payable	15,168	(10,898)	(6,525)
Accrued and other current liabilities	2,559	4,891	1,431
Other non-current assets	(10,518)	1,459	(1,324)
Other non-current liabilities	(310)	(2,215)	(4,169)
Total adjustments from operating activities	(90,717)	26,311	36,870
Net cash provided by continuing operations	56,183	214,962	197,487
Net cash provided by discontinued operations		292	
Net cash provided by operating activities	56,183	215,254	197,487
Cash flows from investing activities:			
Capital expenditures	(87,309)	(120,472)	(67,867)
Acquisitions and equity investments, net of cash acquired	(58,313)	(667,523)	(40,726)
Net proceeds (expenditures) for disposal of property, plant and equipment	1,419	(365)	(12)
Proceeds from the sale of discontinued operations		52,584	
Net cash used in investing activities	(144,203)	(735,776)	(108,605)

Cash flows from financing activities:			
Net proceeds from issuance of limited partner units	104,632	113,111	296,361
Proceeds from exercise of limited partner unit options	3,204	316	2,497
Issuance of long-term debt	273,210	298,050	
Borrowings under credit facilities	317,120	558,554	155,000
Repayments under credit facilities	(537,387)	(260,288)	(300,000)
Net borrowings (repayments) under BES credit agreement	143,800	(4,000)	
Debt issuance costs	(4,691)	(2,111)	(178)
Distributions paid to noncontrolling interests	(5,736)	(4,648)	(3,962)
Settlement payment of interest rate swaps		(9,638)	
Distributions paid to partners	(230,376)	(203,179)	(164,348)
Net cash provided by (used in) financing activities	63,776	486,167	(14,630)
Net increase (decrease) in cash and cash equivalents	(24,244)	(34,355)	74,252
Cash and cash equivalents Beginning of year	58,843	93,198	18,946
Cash and cash equivalents End of year	$ 34,599	$ 58,843	$ 93,198

See Notes to Consolidated Financial Statements.

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

	Buckeye Partners, L.P. Unitholders					
	General Partner	Limited Partners	Receivable from Exercise of Options	Accumulated Other Comprehensive (Loss) Income	Noncontrolling Interests	Total
Partners capital (deficit) January 1, 2007	$ 1,964	$ 807,488	$ (355)	$ 785	$ 20,169	$ 830,051
Net income	27,796	127,560			5,261	160,617
Change in value of derivatives				(7,187)		(7,187)
Amortization of benefit plan costs				(1,929)		(1,929)
Adjustment to funded status of benefit plans				(838)		(838)
Distributions paid to partners	(30,765)	(133,583)				(164,348)
Distributions paid to noncontrolling interests					(3,962)	(3,962)
Net proceeds from the issuance of limited partner units		296,361				296,361
Amortization of unit-based compensation awards		378				378
Exercise of limited partner unit options		2,142				2,142
Repayment of receivable from exercise of options			355			355
Partners capital (deficit) December 31, 2007	(1,005)	1,100,346		(9,169)	21,468	1,111,640
Net income	34,054	150,335			5,492	189,881
Change in value of derivatives				(2,668)		(2,668)
Amortization of interest rate swaps				920		920
Amortization of benefit plan costs				(2,573)		(2,573)
Adjustment to funded status of benefit plans				(5,477)		(5,477)
	(39,729)	(163,450)				(203,179)

Distributions paid to partners						
Distributions paid to noncontrolling interests					(4,648)	(4,648)
Net proceeds from the issuance of limited partner units		113,111				113,111
Amortization of unit-based compensation awards		486				486
Exercise of limited partner unit options		316				316
Acquired noncontrolling interest not previously owned					(1,537)	(1,537)
Partners capital (deficit) December 31, 2008	(6,680)	1,201,144		(18,967)	20,775	1,196,272
Net income	55,153	85,829			5,918	146,900
Change in value of derivatives				17,722		17,722
Amortization of interest rate swaps				961		961
Amortization of benefit plan costs				(1,640)		(1,640)
Adjustment to funded status of benefit plans				1,077		1,077
Distributions paid to partners	(46,624)	(183,752)				(230,376)
Distributions paid to noncontrolling interests					(5,736)	(5,736)
Net proceeds from the issuance of limited partner units		104,632				104,632
Amortization of unit-based compensation awards		3,079				3,079
Exercise of limited partner unit options		3,204				3,204
Partners capital (deficit) December 31, 2009	$ 1,849	$ 1,214,136	$	$ (847)	$ 20,957	$ 1,236,095

See Notes to Consolidated Financial Statements.

BUCKEYE PARTNERS, L.P.
NOTES TO 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

Buckeye Partners, L.P. is a publicly traded master limited partnership (MLP) that owns and operates 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, Buckeye operates and maintains approximately 2,400 miles of other pipelines under agreements with major oil and chemical companies. We also own and operate a major natural gas storage facility in northern California, which provides approximately 40 billion cubic feet (Bcf) of natural gas storage capacity (including pad gas), and are a wholesale distributor of refined petroleum products in the United States in areas also served by our pipelines and terminals. Our limited partner units (LP Units) are listed on the New York Stock Exchange (NYSE) under the ticker symbol BPL. We were formed in 1986 under the laws of the state of Delaware. As used in these Notes to Consolidated Financial Statements, we, us, our, and Buckeye mean Buckeye Partners, L.P. and, where the context requires, includes 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.

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 December 31, 2009, Services Company owned approximately 3.2% 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. Pursuant to the Services Agreement and an executive employment agreement, through December 31, 2008, executive compensation costs and related benefits paid to Buckeye GP s four highest salaried officers were not reimbursed by us or our operating subsidiaries but were reimbursed to Services Company by BGH. Since January 1, 2009, we and our operating subsidiaries have paid for all executive compensation and benefits earned by Buckeye GP s four highest salaried officers in return for an annual fixed payment from BGH of $3.6 million.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

We adhere to the following significant accounting policies in the preparation of our consolidated financial statements.

Basis of Presentation and Principles of Consolidation

The consolidated financial statements and the accompanying notes are prepared in accordance with U.S. generally accepted accounting principles (GAAP) and the rules of the U.S. Securities and Exchange Commission (SEC). The financial statements include our accounts on a consolidated basis. We have eliminated all intercompany transactions in consolidation. The consolidated financial statements do not include the accounts of BGH, Buckeye GP or Services Company. Our results for the year ended December 31, 2008 reflect the operations of Farm & Home Oil Company LLC s (Farm & Home) retail operations as discontinued operations (see Note 4 for further discussion).

Business Segments

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

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

Logistics segment as the Other Operations segment. We renamed the segment to better describe the business activities conducted within the segment. See Note 23 for a more detailed discussion of our business segments.

Asset Retirement Obligations

We regularly assess our legal obligations with respect to estimated retirements of certain of our long-lived assets to determine if an asset retirement obligation (ARO) exists. GAAP requires that the fair value of a liability related to the retirement of long-lived assets be recorded at the time a legal obligation is incurred including obligations to perform an asset retirement activity in which the timing or method of settlement are conditional on a future event that may or may not be within the control of the entity. If an ARO is identified and a liability is recorded, a corresponding asset is recorded concurrently and is depreciated over the remaining useful life of the asset. After the initial measurement, the liability is periodically adjusted to reflect changes in the ARO s fair value. Generally, the fair value of any liability is determined based on estimates and assumptions related to future retirement costs, future inflation rates and credit-adjusted risk-free interest rates.

Other than assets in the Natural Gas Storage segment, our assets generally consist of underground refined petroleum products pipelines installed along rights-of-way acquired from land owners and related above-ground facilities and terminals that we own. We are unable to predict if and when our pipelines, which generally serve high-population and high-demand markets, will become completely obsolete and require decommissioning. Further, our rights-of-way agreements typically do not require the dismantling and removal of the pipelines and reclamation of the rights-of-way upon permanent removal of the pipelines from service. Accordingly, other than with respect to the Natural Gas Storage segment, we have recorded no liabilities, or corresponding assets, because the future dismantlement and removal dates of the majority of our assets, and the amount of any associated costs, are indeterminable.

The Natural Gas Storage segment s pipelines and surface facilities are located on land that is leased. An ARO asset and liability was established due to a requirement in the land leases to remove certain assets in the event that the site is abandoned. The ARO liability will be adjusted prospectively for costs incurred or settled, accretion expense, and any revisions made to the assumptions related to the retirement costs. See Note 8 for further discussion of our AROs.

Capitalization of Interest

Interest on borrowed funds is capitalized on projects during construction based on the approximate average interest rate of our debt. Interest capitalized for the years ended December 31, 2009, 2008 and 2007 was $3.4 million, $2.3 million and $1.5 million, respectively. The weighted average rates used to capitalize interest on borrowed funds was 5.4% for the years ended December 31, 2009, 2008 and 2007.

Cash and Cash Equivalents

Cash equivalents represent all highly marketable securities with original maturities of three months or less. The carrying value of cash equivalents approximates fair value because of the short term nature of these investments.

Our consolidated statements of cash flows are prepared using the indirect method. The indirect method derives net cash flows from operating activities by adjusting net income to remove (i) the effects of all deferrals of past operating cash receipts and payments, such as changes during the period in inventory, deferred income and similar transactions, (ii) the effects of all accruals of expected future operating cash receipts and cash payments, such as changes during the period in receivables and payables, (iii) the effects of all items classified as investing or financing cash flows, such as gains or losses on sale of property, plant and equipment or extinguishment of debt, and (iv) other non-cash amounts such as depreciation, amortization and changes in the fair market value of financial instruments.

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

Comprehensive Income (Loss)

Our comprehensive income (loss) is determined based on net income adjusted for changes in other comprehensive income (loss) from certain of our hedging transactions, related amortization of our pension and post-retirement benefit plan costs and changes in the funded status of our pension and post-retirement benefit plans.

Construction and Pipeline Relocation Receivables

Construction and pipeline relocation receivables represent valid claims against non-affiliated customers for services rendered in constructing or relocating pipelines and are recognized when services are rendered.

Contingencies

Certain conditions may exist as of the date our consolidated financial statements are issued that may result in a loss to us, but which will only be resolved when one or more future events occur or fail to occur. Our management, with input from legal counsel, assesses such contingent liabilities, and such assessment inherently involves an exercise in judgment. In assessing loss contingencies related to legal proceedings that are pending against us or unasserted claims that may result in proceedings, our management, with input from legal counsel, evaluates the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

If the assessment of a contingency indicates that it is probable that a material loss has been incurred and the amount of liability can be estimated, then the estimated liability would be accrued in our consolidated financial statements. If the assessment indicates that a potentially material loss contingency is not probable but is reasonably possible, or is probable but cannot be estimated, then the nature of the contingent liability, together with an estimate of the range of possible loss if determinable and material, is disclosed.

Loss contingencies considered remote are generally not disclosed unless they involve guarantees, in which case the guarantees would be disclosed.

Cost of Product Sales and Natural Gas Storage Services

Cost of product sales relates to sales of refined petroleum products, consisting primarily of gasoline, heating oil and diesel fuel, and includes the direct costs of product acquisition as well as the effects of hedges of such product acquisition costs and hedges of fixed-price sales contracts. In addition, costs related to hub service agreements, which consist of a variety of gas storage services under interruptible storage agreements, for which we will be required to make payment to a third party, are recognized as cost of natural gas storage services. These services principally include park and loan transactions. Parks occur when gas from a third party is injected and stored for a specified period. The third party then is obligated to withdraw its stored gas at a future date. Title to the gas remains with the third party. Loans occur when gas is delivered to a third party in a specified period. The third party then has the obligation to redeliver gas at a future date. Costs related to park and loan transactions for which we are required to make payment are recognized ratably over the term of the agreement.

Debt Issuance Costs

Costs incurred upon the issuance of our debt instruments are capitalized and amortized over the life of the associated debt instrument on a straight-line basis, which approximates the effective interest method. If the debt instrument is retired before its scheduled maturity date, any remaining issuance costs associated with that debt instrument are expensed in the same period. Deferred debt issuance costs were $18.1 million and $13.7 million at December 31, 2009 and 2008, respectively. Accumulated amortization was approximately $7.0 million and $4.8 million at December 31, 2009 and 2008, respectively.

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

Earnings per LP Unit

Basic earnings per LP Unit is determined by dividing our limited partners allocation of net income per the two-class method by the weighted average number of LP Units outstanding for the period. Diluted earnings per LP Unit is calculated the same way except the weighted average LP Units outstanding include any dilutive effect of LP Unit option grants or grants under the 2009 Long-Term Incentive Plan of Buckeye Partners, L.P. (the 2009 LTIP) (see Note 22).

Environmental Expenditures

We accrue for environmental costs that relate to existing conditions caused by past operations, including, in some cases, pre-existing conditions related to acquired assets. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Environmental costs include initial site surveys and environmental studies of potentially contaminated sites, costs for remediation and restoration of sites determined to be contaminated and ongoing monitoring costs, as well as damages and other costs, when estimable. We monitor the balance of accrued undiscounted environmental liabilities on a regular basis. We record liabilities for environmental costs at a specific site when our liability for such costs is probable and a reasonable estimate of the associated costs can be made. Adjustments to initial estimates are recorded, from time to time, to reflect changing circumstances and estimates based upon additional information developed in subsequent periods. Estimates of our ultimate liabilities associated with environmental costs are particularly difficult to make with certainty due to the number of variables involved, including the early stage of investigation at certain sites, the lengthy time frames required to complete remediation alternatives available and the evolving nature of environmental laws and regulations. None of our estimated environmental remediation liabilities are discounted to present value since the ultimate amount and timing of cash payments for such liabilities are not readily determinable. Expenditures to mitigate or prevent future environmental contamination are capitalized. We maintain insurance which may cover certain environmental expenditures.

At December 31, 2009 and 2008, our accrued liabilities for environmental remediation projects totaled $29.9 million and $27.0 million, respectively. These amounts were derived from a range of reasonable estimates based upon studies and site surveys. Unanticipated changes in circumstances and/or legal requirements could result in expenses being incurred in future periods in addition to an increase in expenditures required to remediate contamination for which we are responsible.

Equity Investments

We account for investments in entities in which we do not exercise control, but have significant influence, using the equity method. Under this method, an investment is recorded at acquisition cost plus our equity in undistributed earnings or losses since acquisition, reduced by distributions received and amortization of excess net investment. Excess investment is the amount by which the initial investment exceeds the proportionate share of the book value of the net assets of the investment. We evaluate equity method investments for impairment whenever events or circumstances indicate that there is a loss in value of the investment which is other than temporary. In the event that the loss in value of an investment is other than temporary, we record a charge to earnings to adjust the carrying value to fair value. There were no impairments of our equity investments during the years ended December 31, 2009, 2008 or 2007.

Estimates

The preparation of consolidated financial statements in conformity with GAAP requires our management to make estimates and assumptions. These estimates and assumptions, which may differ from actual results, will affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements, as well as the reported amounts of revenue and expense during the reporting periods.

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

Fair Value

Cash and cash equivalents, trade receivables, construction and pipeline relocation receivables, margin deposits, prepaid and other current assets and all current liabilities are reported in the consolidated balance sheets at amounts which approximate fair value due to the relatively short period to maturity of these financial instruments. The fair value of our debt was calculated using interest rates currently available to us for issuance of debt with similar terms and remaining maturities and approximate market values on the respective dates. 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 Energy Services segment also has derivative assets and liabilities. These assets and liabilities consist of exchange traded futures contracts and fixed-price sales contracts with customers. These assets and liabilities are measured and reported at fair values. We consider the impact of credit valuation adjustments with respect to the fixed-price sales contracts. See Note 16 for further discussion.

Financial Instruments

We use financial instruments such as swaps, forwards, futures and other contracts to manage market price risks associated with inventories, firm commitments, interest rates and certain anticipated transactions. We recognize these transactions on our consolidated balance sheet as assets and liabilities based on the instrument s fair value. Changes in fair value of financial instrument derivative contracts are recognized in the current period in earnings unless specific hedge accounting criteria are met. If the financial instrument is designated as a hedging instrument in a fair value hedge, gains and losses incurred on the instrument will be recorded in earnings to offset corresponding losses and gains on the hedged item. If the financial instrument is designated as a hedging instrument in a cash flow hedge, gains and losses incurred on the instrument are recorded in other comprehensive income. In both cases, any gains or losses incurred on the instrument that are not effective in offsetting changes in fair value or cash flows of the hedged item are recognized immediately in earnings. Gains and losses on cash flow hedges are reclassified from other comprehensive income to earnings when the forecasted transaction occurs or, as appropriate, over the economic life of the underlying asset or liability. A financial instrument designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify as a hedge, the item to be hedged must expose us to risk and we must have an expectation that the related hedging instrument will be effective at reducing or mitigating that exposure. Certain other hedging requirements, such as documentation at inception as discussed below, must also be met.

Documentation of all hedging relationships is completed at inception and includes a description of the risk-management objective and strategy for undertaking the hedge, identification of the hedging instrument, the hedged item, the nature of the risk being hedged, the method for assessing effectiveness of the hedging instrument in offsetting the hedged risk and the method of measuring any ineffectiveness. This process includes linking all derivatives that are designated as fair value or cash flow hedges to specific assets and liabilities on the consolidated balance sheets or to specific firm commitments or forecasted transactions. We also formally assess, both at the hedge s inception and on an ongoing basis at least quarterly, whether the derivatives that are used in designated hedging relationships are highly effective in offsetting changes in fair values or cash flows of hedged items. If it is determined that a derivative is not highly effective as a hedge or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively.

Goodwill

Goodwill represents the excess of purchase price over fair value of net assets acquired. Our goodwill amounts are assessed for impairment (i) on an annual basis on January 1 of each year or (ii) on an interim basis if circumstances indicate it is more likely than not the fair value of a reporting unit is less than its fair value. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. A reporting unit is a business segment or one level below a business segment for which discrete financial information is available and regularly reviewed by segment management. Our reporting units are our business segments. A goodwill impairment assessment requires that the estimated fair value of the reporting unit to which the goodwill is assigned be determined and

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compared to its book value. If the fair value of the reporting unit including associated goodwill amounts is less than its book value, including associated goodwill amounts, a charge to earnings is recorded to reduce the carrying value of the goodwill to its implied fair value. We have not recognized any impairment losses related to goodwill for any of the periods presented.

Income Taxes

For federal and state income tax purposes, we and each of our subsidiaries, except for Buckeye Gulf Coast Pipe Lines, L.P. (BGC), are not taxable entities. Accordingly, our taxable income, except for BGC, is generally includable in the federal and state income tax returns of our individual partners.

Effective August 1, 2004, BGC elected to be treated as a taxable corporation for federal income tax purposes. Accordingly, it has recognized deferred tax assets and liabilities for temporary differences between the amounts of assets and liabilities measured for financial reporting purposes and the amounts measured for federal income tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. Deferred tax assets are reduced by a valuation allowance when the amount of any tax benefit is not expected to be realized. We recorded a deferred tax liability of $0.4 million and $0.8 million as of December 31, 2009 and 2008, respectively, which is recorded in non-current liabilities. As of December 31, 2009 and 2008, our reported amount of net assets for GAAP purposes exceeded our tax basis for allocating taxable income under our partnership agreement.

Income tax benefit for the year ended December 31, 2009 was $0.3 million. Income tax expense for the years ended December 31, 2008 and 2007 was $0.8 million for both periods. Income tax benefit/expense is included in operating expenses in the consolidated statements of operations.

Intangible Assets

Intangible assets with finite useful lives are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Intangible assets that have finite useful lives are amortized over their useful lives.

Inventories

We generally maintain two types of inventory. Within our Energy Services segment, we principally maintain refined petroleum products inventory, which consists primarily of gasoline, heating oil and diesel fuel, which are valued at the lower of cost or market, unless such inventories are hedged.

We also maintain, principally within our Pipeline Operations segment, an inventory of materials and supplies such as pipes, valves, pumps, electrical/electronic components, drag reducing agent and other miscellaneous items that are valued at the lower of cost or market based on the first-in, first-out method (see Note 6).

Long-Lived Assets

We assess the recoverability of our long-lived assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. We assess recoverability based on estimated undiscounted future cash flows expected to result from the use of the asset and its eventual disposal. The measurement of an impairment loss, if recognition of any loss is required, is based on the difference between the carrying amount and fair value of the asset. During the year ended December 31, 2009, we recorded a non-cash charge of $59.7 million related to an asset impairment (see Note 8).

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Net Income Allocation

We allocate net income to our partners for two primary purposes: (i) under the two-class method for purposes of computing earnings per LP Unit and (ii) in accordance with the partnership agreement for purposes of maintaining our limited partners and general partner s capital accounts.

Specific accounting standards applicable to MLPs, including us, became effective January 1, 2009, which prescribe the application of the two-class method in computing earnings per unit to reflect an MLP s contractual obligation to make distributions to its general partner, limited partners and incentive distribution rights holders. As a result, our earnings allocation to the general partner now includes incentive distributions that were declared subsequent to the quarter end. Prior to the adoption of these accounting standards, our general partner s earnings allocation included incentive distributions that were declared during each quarter. We have applied these accounting standards on a retrospective basis. The adoption of these accounting standards resulted in a decrease in our limited partners interest in net income attributable to Buckeye for purposes of computing earnings per LP Unit for the years ended December 31, 2008 and 2007, reducing diluted earnings per LP Unit by $0.15 to $3.00 and $0.12 to $2.91, respectively (see Note 22).

In accordance with our partnership agreement, we allocate net income to our limited partners and our general partner based upon their respective ownership interests in us. We first allocate net income to our general partner based on the incentive distributions paid during the current quarter. After the allocation of the incentive distribution interests, the general partner and limited partners share in the remaining income or loss based upon their proportionate interest in us.

Noncontrolling Interests

The consolidated balance sheets include noncontrolling interests that relate primarily to the portions of Sabina Pipeline, Wes Pac Pipelines Memphis LLC and an approximate 1% interest in certain of our operating subsidiaries that are not owned by us. Similarly, the consolidated statements of operations include noncontrolling interests that reflect amounts not attributable to us. On January 1, 2009, we adopted guidance that established accounting and reporting standards for the noncontrolling interests in a subsidiary and for the deconsolidation of a subsidiary. These accounting and reporting standards require entities that prepare consolidated financial statements to: (a) present noncontrolling interests as a component of equity, separate from the parent s equity; (b) separately present the amount of consolidated net income attributable to noncontrolling interests in the income statement; (c) consistently account for changes in a parent s ownership interests in a subsidiary in which the parent entity has a controlling financial interest as equity transactions; (d) require an entity to measure at fair value its remaining interest in a subsidiary that is deconsolidated; and (e) require an entity to provide sufficient disclosures that identify and clearly distinguish between interests of the parent and interests of noncontrolling owners. Accordingly, for all periods presented in our consolidated financial statements, we have reclassified our noncontrolling interests liability into partners capital on the consolidated balance sheets and have separately presented and allocated income attributable to noncontrolling interests on the consolidated statements of operations and consolidated statements of partners capital.

Pensions

Services Company sponsors a defined contribution plan (see Note 17), defined benefit plans (see Note 17) and the ESOP (see Note 19) that provide retirement benefits to certain regular full-time employees. Certain hourly employees of Services Company are covered by a defined contribution plan under a union agreement (see Note 17). These plans are included in our consolidated financial statements because we are a guarantor of these obligations.

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Postretirement Benefits Other Than Pensions

Services Company provides post-retirement health care and life insurance benefits for certain of its retirees. Certain other retired employees are covered by a health and welfare plan under a union agreement (see Note 17). This plan is included in our consolidated financial statements because we are a guarantor of these obligations.

Property, Plant and Equipment

We record property, plant and equipment at its original acquisition cost. Property, plant and equipment consist primarily of pipelines, wells, storage and terminal facilities, pad gas and pumping and compression equipment. Depreciation on pipelines and terminals is generally calculated using the straight-line method over the estimated useful lives ranging from 44 to 50 years. Plant and equipment associated with natural gas storage is generally depreciated over 44 years, except for pad gas. The Natural Gas Storage segment maintains a level of natural gas in its underground storage facility generally known as pad gas, which is not routinely cycled but, instead, serves the function of maintaining the necessary pressure to allow routine injection and withdrawal to meet demand. The pad gas is considered to be a component of the facility and as such is not depreciated because it is expected to ultimately be recovered and sold. Other plant and equipment is generally depreciated on a straight-line basis over an estimated life of 5 to 50 years.

Additions to property, plant and equipment, including major replacements or betterments, are recorded at cost. We charge maintenance and repairs to expense in the period incurred. The cost of property, plant and equipment sold or retired and the related depreciation, except for certain pipeline system assets, are removed from our consolidated balance sheet in the period of sale or disposition, and any resulting gain or loss is included in income. For our pipeline system assets, we generally charge the original cost of property sold or retired to accumulated depreciation and amortization, net of salvage and cost of removal. When a separately identifiable group of assets, such as a stand-alone pipeline system is sold, we will recognize a gain or loss in our consolidated statements of operations for the difference between the cash received and the net book value of the assets sold.

The following table represents the depreciation life for the major components of our assets:

	Life in years
Right of way	44-50
Line pipe and fittings	44-50
Buildings	50
Wells	44
Pumping and compression equipment	44-50
Oil tanks	50
Office furniture and equipment	18
Vehicles and other work equipment	11
Servers and software	5

Recent Accounting Developments

In June 2009, the Financial Accounting Standards Board (FASB) established the FASB Accounting Standards Codification (ASC). Beginning in the third quarter of 2009, the ASC became the single source for all authoritative nongovernmental GAAP recognized by the FASB and is required to be applied to financial statements issued for interim and annual periods ending after September 15, 2009. The ASC replaces other sources of authoritative GAAP with the exception of rules and interpretive releases of the SEC, which will continue to be authoritative. The issuance of the ASC is not intended to significantly change GAAP and did not impact our results of operations, cash flows or financial position.

BUCKEYE PARTNERS, L.P.
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Consolidation of Variable Interest Entities (VIEs). In June 2009, the 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 companies to perform an analysis to determine whether the companies variable interest or interests give it a controlling financial interest in a VIE. The new guidance is effective as of the beginning of each reporting company s first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period, and for interim and annual reporting periods thereafter. Earlier application is prohibited. This guidance is effective for us on January 1, 2010. We are currently evaluating the impact the adoption of this guidance will have on our consolidated financial statements.

Fair Value Measurements. In August 2009, the FASB issued new guidance that clarifies how an entity should estimate the fair value of liabilities. If a quoted price in an active market for an identical liability is not available, a company must measure the fair value of the liability using one of several valuation techniques (e.g., quoted prices for similar liabilities or present value of cash flows). Our adoption of this new guidance on October 1, 2009 did not have any impact on our consolidated financial statements or related disclosures.

In January 2010, the FASB issued new guidance that amends, clarifies and provides additional disclosure requirements related to recurring and non-recurring fair value measurements and employers disclosures about postretirement benefit plan assets. This new guidance became effective for us on January 1, 2010. We are currently evaluating the impact the adoption of this guidance will have on our consolidated financial statements.

Reclassifications

Certain prior year amounts have been reclassified in the consolidated statements of operations and consolidated statements of cash flows to conform to the current-year presentation. We are also presenting other comprehensive income in a separate financial statement rather than including it in our consolidated statements of partners capital. These reclassifications in the consolidated statements of operations are as follows:

- Earnings from equity investments are now presented on a separate line item in the consolidated statements of operations. The other investment income that had previously been included with earnings from equity investments has been reclassified and included in Other income.

The reclassifications in the consolidated statements of cash flows are as follows:

- We have separately disclosed cash flows from the issuance of long-term debt and borrowings under our credit facilities for the year ended December 31, 2008. These amounts had been included within the same line item in the 2008 period. There were no issuances of long-term debt during the year ended December 31, 2007.

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

Regulatory Reporting

The majority of our refined petroleum products pipelines are subject to regulation by the Federal Energy Regulatory Commission (FERC), which prescribes certain accounting principles and practices for the annual Form 6 Report filed with the FERC that differ from those used in these consolidated financial statements. Reports to FERC differ from the consolidated financial statements, which have been prepared in accordance with GAAP, generally in that such reports calculate depreciation over estimated useful lives of the assets as prescribed by FERC.

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Revenue Recognition

We recognize revenues as follows (by segment):

Pipeline Operations segment:

Revenue from the transportation of refined petroleum products is recognized as products are delivered.

Terminalling and Storage segment:

Revenues from terminalling, storage and rental operations are recognized as the services are performed.

Natural Gas Storage segment:

Revenue from natural gas storage, which consists of demand charges, or lease revenues, for the reservation of storage space under firm storage agreements, is recognized over the term of the related storage agreement. The demand charge entitles the customer to a fixed amount of storage space and certain injection and withdrawal rights. Title to the stored gas remains with the customer.

Revenues from hub services, which consist of a variety of other gas storage services under interruptible storage agreements, are recognized ratably over the term of the agreement. These services principally include park and loan transactions. Parks occur when gas from a customer is injected and stored for a specified period. The customer then has the obligation to withdraw its stored gas at a future date. Title to the gas remains with the customer. Loans occur when gas is delivered to a customer in a specified period. The customer then has the obligation to redeliver gas at a future date.

Energy Services segment:

Revenue from the sale of refined petroleum products, which are sold on a wholesale basis, is recognized when such products are delivered to the customer purchasing the products.

Development and Logistics segment:

Revenues from contract operation and construction services of facilities and pipelines not directly owned by us are recognized as the services are performed. Contract and construction services revenue typically includes costs to be reimbursed by the customer plus an operator fee.

Trade Receivables and Concentration of Credit Risk

Trade receivables represent valid claims against non-affiliated customers and are recognized when products are sold or services are rendered. We extend credit terms to certain customers based on historical dealings and to other customers after a full review of various financial credit indicators, including the customers credit rating (if available), and verified trade references. Our allowance for doubtful accounts is determined based on specific identification and estimates of future uncollectible accounts. Our Energy Services segment has established an allowance for doubtful accounts, while our other segments do not maintain an allowance for doubtful accounts due to their favorable collections experience.

Our Energy Services segment s allowance for doubtful accounts was $1.5 million and $2.1 million at December 31, 2009 and 2008, respectively, and is included in trade receivables in the consolidated balance sheets. Our procedure for determining the allowance for doubtful accounts is based on (i) historical experience with customers, (ii) the perceived financial stability of customers based on our research, and (iii) the levels of credit the Energy Services segment grants to customers. In addition, the Energy Services segment may increase the allowance for doubtful accounts in response to the specific identification of customers involved in bankruptcy proceedings and similar financial difficulties. On a routine basis, we review estimates associated with the allowance for doubtful accounts to ensure that we have recorded sufficient reserves to cover potential losses.

We have a concentration of trade receivables due from major integrated oil companies and their marketing affiliates, major petroleum refiners, major chemical companies, large regional marketing companies and large commercial airlines. Additionally, we have trade receivables from gas marketing companies, independent gatherers,

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investment banks that have established a trading platform, and brokers and marketers. These concentrations of customers may affect our overall credit risk in that the customers may be similarly affected by changes in economic, regulatory or other factors.

For the years ended December 31, 2009 and 2008, no customer contributed more than 10% of consolidated revenue. For the year ended December 31, 2007, Shell Oil Products U.S. (Shell) contributed 10% of consolidated revenue. Approximately 3% of 2007 consolidated revenue was generated by Shell in the Pipeline Operations segment, and the remaining 7% of consolidated revenue generated by Shell was in the Terminalling and Storage segment.

We manage our exposure to credit risk through credit analysis and monitoring procedures, and sometimes use letters of credit, prepayments and guarantees. The Pipeline Operations and Energy Services segments bill their customers on a weekly basis, and the Terminalling and Storage, Natural Gas Storage and Development and Logistics segments bill on a monthly basis. We believe that these billing practices may reduce credit risk.

Unit-Based Compensation

We formerly awarded options to acquire LP Units to employees pursuant to a Unit Option and Distribution Equivalent Plan (the Option Plan). In addition, in March 2009, the 2009 LTIP became effective. All unit-based payments to employees under these plans, including grants of employee unit options, phantom units and performance units, are recognized in the consolidated statements of operations based on their fair values. See Note 18 for further discussion of our unit-based compensation plans.

3. REORGANIZATION

On July 20, 2009, we announced the completion of a company-wide, best practices review. During the period ended June 30, 2009, we commenced a restructuring of our operations as a result of this review, including a reorganization of our field operations to combine five of our original pipeline and terminal districts into three districts, as well as a restructuring of certain corporate functions and related corporate support functions. These efforts redefined the roles and responsibilities of certain positions and called for the elimination of resources devoted to such activities. Approximately 230 positions have been affected as a result of these restructuring activities.

As part of the restructuring efforts, we executed a reduction in force comprised of a Voluntary Early Retirement Plan (the VERP) and an involuntary plan. The terms of the VERP were agreed to by approximately 80 employees during the period ended June 30, 2009. An additional group of approximately 150 employees were impacted by the involuntary reduction in workforce under our ongoing severance plan. Affected employees receive severance benefits, post-employment benefits including extended medical and dental coverage, and other services including retirement counseling and outplacement services. Most terminations were effective as of July 20, 2009.

For the year ended December 31, 2009, we recorded reorganization expense of $32.1 million for post-employment costs related to these restructuring activities which include: (1) termination benefits pursuant to voluntary and involuntary severance plans of $16.0 million; (2) post-retirement benefits of $6.4 million (see Note 17); and (3) other related costs of $9.7 million.

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The reorganization expenses incurred by segment, including certain allocated amounts, for the year ended December 31, 2009 were as follows:

Pipeline Operations	$ 26,127
Terminalling and Storage	2,735
Natural Gas Storage	495
Energy Services	1,207
Development and Logisitics	1,493
Total reorganization expenses	$ 32,057

4. ACQUISITIONS AND DISCONTINUED OPERATIONS

Business Combinations

Our 2009 acquisition of pipeline and terminal assets from ConocoPhillips and the 2008 acquisitions of Lodi Gas Storage, L.L.C. (Lodi Gas), Farm & Home and a terminal in Albany, New York (Albany Terminal) have been accounted for as business combinations. The total purchase price was allocated to the fair value of the assets acquired and the liabilities assumed based on an assessment of their fair values at the acquisition date, with amounts exceeding the fair values being recorded as goodwill. All goodwill recorded in these business combinations is deductible for tax purposes. The results of their operations have been included in our consolidated financial statements since their respective acquisition dates.

Refined Petroleum Products Terminals and Pipeline Assets

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 gives us greater access to markets and refinery operations in the Midwest and increases the commercial value to our customers by offering enhanced distribution connectivity and flexible storage capabilities. The operations of our combined assets will be reported in the Pipeline Operations and Terminalling and Storage segments. The purchase price has been allocated to the tangible and intangible assets acquired, on a preliminary basis, 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

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Lodi Gas

On January 18, 2008, we acquired all of the member interests in Lodi Gas from Lodi Holdings, L.L.C. Lodi Holdings, L.L.C. was owned by affiliates of ArcLight Capital Partners, LLC (ArcLight), which owns an indirect interest in our general partner. The cost of Lodi Gas was approximately $442.4 million in cash and consisted of the following:

Contractual purchase price	$ 440,000
Working capital adjustments and fees	2,367
Total purchase price	$ 442,367

Of the contractual purchase price, $428.0 million was paid at closing and an additional $12.0 million was paid on March 6, 2008 upon receipt of approval from the California Public Utilities Commission for an expansion project known as Kirby Hills Phase II. We believed the acquisition of Lodi Gas represented an attractive opportunity to expand and diversify our storage and throughput operations into a new geographic area, northern California, and a new commodity type, natural gas, and provides us a platform for growth in the natural gas storage industry. These advantageous factors resulted in the recognition of goodwill in the amount that the fair value of the assets acquired and the liabilities assumed at the acquisition date exceeded the total purchase price. The activities of Lodi Gas are reported in the Natural Gas Storage segment. The purchase price has been allocated to the tangible and intangible assets acquired, including goodwill, as follows:

Current assets	$ 8,240
Property, plant and equipment	274,880
Goodwill	169,560
Current liabilities	(9,096)
Other liabilities	(1,217)
Allocated purchase price	$ 442,367

Farm & Home

On February 8, 2008, we acquired all of the member interests of Farm & Home for approximately $146.2 million. We believed that the wholesale distribution operations of Farm & Home represented an attractive opportunity to further our strategy of improving overall profitability by increasing the utilization of our existing pipeline and terminal system infrastructure by marketing refined petroleum products in areas served by that infrastructure. These advantageous factors resulted in the recognition of goodwill in the amount that the fair value of the assets acquired and the liabilities assumed at the acquisition date exceeded the total purchase price. The operations of Farm & Home are reported in the Energy Services segment. The purchase price has been allocated to the tangible and intangible assets acquired, including goodwill, as follows:

Current assets	$ 79,144
Inventory	93,332
Property, plant and equipment	33,880
Goodwill	1,132
Customer relationships	38,300
Other assets	3,688
Assets held for sale, net of liability of $0.7 million	51,645

Debt	(100,000)
Current liabilities	(53,208)
Other liabilities	(1,740)
Allocated purchase price	$ 146,173

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On April 15, 2008, we completed the sale of the retail operations of Farm & Home to a wholly-owned subsidiary of Inergy, L.P. for approximately $52.6 million. The retail assets sold consisted primarily of property, plant and equipment, inventory and receivables. We recorded no gain or loss on the sale of Farm & Home s retail operations. The retail operations of Farm & Home were not an integral part of our core operations and strategy, and the related retail assets and liabilities were determined to be discontinued operations on the date of our acquisition of Farm & Home because we decided to dispose of them as of that date. Revenues from discontinued operations for the period February 8, 2008 to April 15, 2008 were approximately $19.0 million. On July 31, 2008, Farm & Home was merged with and into its wholly owned subsidiary, Buckeye Energy Services LLC (BES), with BES continuing as the surviving entity of the merger.

Albany Terminal

On August 28, 2008, we completed the purchase of the Albany Terminal, an ethanol and refined petroleum products terminal in Albany, New York, from LogiBio Albany Terminal, LLC. The purchase price for the terminal was $46.5 million in cash, with an additional $1.5 million payable if the terminal operations meet certain performance goals over the next three years. We also assumed environmental remediation costs for the Albany Terminal estimated to be $5.6 million. The Albany Terminal has an active storage capacity of 1.8 million barrels. The Albany Terminal s operations are reported in the Terminalling and Storage segment. We believe that the Albany Terminal s operations represented an attractive opportunity to increase our participation in the ethanol services market in the northeast United States. These advantageous factors resulted in the recognition of goodwill in the amount that the fair value of the assets acquired and the liabilities assumed at the acquisition date exceeded the total purchase price. The purchase price has been allocated to the tangible and intangible assets acquired, including goodwill, as follows:

Current assets	$ 78
Property, plant and equipment	25,172
Goodwill	26,829
Other assets	1,920
Other liabilities	(7,144)
Allocated purchase price	$ 46,855

Unaudited Pro forma Financial Results

The following unaudited summarized pro forma consolidated statements of operations information for the years ended December 31, 2008 and 2007 assumes that the acquisitions of Lodi Gas, Farm & Home and the Albany Terminal occurred as of the beginning of the years presented.

The pro forma presentation below assumes that our equity offerings that were used in part to fund the acquisition of Lodi Gas occurred effective January 1, 2007. In the 2008 pro forma presentation, approximately $2.6 million of disposition-related expenses incurred by Lodi Gas in the period from January 1, 2008 to January 17, 2008 (prior to our ownership) have been excluded because these expenses were a nonrecurring item. For Farm & Home, the results of the retail operations have been excluded from both periods presented. These pro forma unaudited financial results were prepared for comparative purposes only and are not indicative of actual results that would have occurred if we had completed these acquisitions as of the beginning of the periods presented or the results that may be attained in the future:

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	(Unaudited) Year Ended December 31,	
	2008	**2007**
Revenues:		
As reported	$ 1,896,652	$ 519,347
Pro forma adjustments	180,422	1,155,655
Pro forma revenue	$ 2,077,074	$ 1,675,002
Income from continuing operations:		
As reported	$ 188,651	$ 160,617
Pro forma adjustments	3,394	24,944
Pro forma income from continuing operations	$ 192,045	$ 185,561
Allocation of pro forma income from continuing operations:		
Allocated to general partner	$ 34,308	$ 32,259
Allocated to limited partners	$ 157,737	$ 153,302
Pro forma earnings from continuing operations per LP Unit: (1)		
Basic	$ 3.00	$ 3.05
Diluted	$ 3.00	$ 3.05
Pro forma weighted average number of LP Units outstanding:		
Basic	48,409	48,281
Diluted	48,425	48,331

(1) Earnings per LP Unit has been restated due to the adoption of guidance regarding the calculation of earnings per LP Unit as it relates to MLPs.

Asset Acquisitions

The acquisitions noted below were accounted for as asset acquisitions. Accordingly, the total purchase price has been allocated to the fair value of the assets acquired and the liabilities assumed based on fair values at the acquisition date. We determined that substantially all of the value of these purchases relate to the physical assets acquired, which are generally depreciated over 50 years. The acquired pipelines and related assets were allocated to the Pipeline Operations segment and the acquired terminals and related assets were allocated to the Terminalling and Storage segment. See Note 23 for a summary of the allocation of acquisitions by segment.

On February 19, 2008, we acquired a refined petroleum products terminal in Niles, Michigan and a 50% ownership interest in a refined petroleum products terminal in Ferrysburg, Michigan from an affiliate of ExxonMobil Corporation for approximately $13.9 million. The approximate fair value allocation of the acquired assets is as follows:

Land	$ 592
Buildings	1,621
Machinery, equipment, and office furnishings	11,714
Allocated purchase price	$ 13,927

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Effective May 1, 2008, we purchased the 50% member interest in WesPac Pipelines San Diego LLC not already owned by us from Kealine LLC for $9.3 million. The operations of WesPac Pipelines San Diego LLC are reported in the Pipeline Operations segment. The purchase price was allocated principally to property, plant and equipment.

On June 20, 2008, we acquired a refined petroleum products terminal in Wethersfield, Connecticut from Hess Corporation for approximately $5.5 million. The purchase price was allocated principally to property, plant and equipment.

On January 16, 2007, we acquired two refined petroleum products terminals located in Flint and Woodhaven, Michigan for approximately $22.2 million, including a deposit of $1.0 million that was paid in 2006. The fair value allocation of the acquired assets is as follows:

Land	$ 8,663
Buildings	3,481
Machinery, equipment, and office furnishings	10,024
Allocated purchase price	$ 22,168

On February 27, 2007, we acquired a refined petroleum products terminal in Marcy, New York for approximately $2.3 million. The purchase price was allocated principally to property, plant and equipment.

On March 15, 2007, we completed the acquisition of two refined petroleum products terminals located in Green Bay and Madison, Wisconsin and the purchase of a 50% interest in a third terminal located in Milwaukee, Wisconsin for approximately $15.2 million. The fair value allocation of the acquired assets is as follow:

Land	$ 3,400
Buildings	1,100
Machinery, equipment, and office furnishings	10,660
Allocated purchase price	$ 15,160

5. 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.

On December 10, 2009, we entered into a Stipulation and Order of Settlement with the Tax Commission of the City of New York and the Commissioner of Finance of the City of New York with respect to a dispute over property tax assessments related to the years 2004 through 2009. We had previously paid the taxes for those years but protested portions of those property taxes, as permitted by state law. As a result of this settlement, we agreed to withdraw the protest and are entitled to receive a refund of approximately $7.2 million of the previously paid property taxes.

In March 2007, we were named as a defendant in an action entitled *Madigan v. Buckeye Partners, L.P.* filed in the U.S. District Court for the Central District of Illinois. The action was brought by the State of Illinois Attorney General acting on behalf of the Illinois Environmental Protection Agency. The complaint alleged that we violated various Illinois state environmental laws in connection with a product release from our terminal located in Harristown, Illinois on or about June 11, 2006 and various other product releases from our terminals and pipelines in

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the State of Illinois during the period of 2001 through 2006. Pursuant to a Consent Decree that was filed with the U.S. District Court for the Central District of Illinois on October 7, 2009, we agreed to settle and compromise the disputed claims without admitting any of the allegations set forth in the complaint. Under the terms of the Consent Decree, we paid approximately $0.4 million in October 2009 to the Illinois Environmental Protection Agency and agreed to continue to perform monitoring and certain remediation activities at the sites involved, and the State of Illinois agreed to release us from any further liability with respect to the claims involved.

Environmental Contingencies

In accordance with our accounting policy, we recorded operating expenses, net of insurance recoveries, of $10.6 million, $10.1 million and $7.4 million during the years ended December 31, 2009, 2008 and 2007, respectively, related to environmental expenditures unrelated to claims and proceedings.

Ammonia Contract Contingencies

On November 30, 2005, 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. Given the uncertainty of future ammonia prices and EPME s future actions, we are unable to estimate the amount of any such losses we might incur in the future. We are assessing our options, including potential recourse against EPME and El Paso, with respect to this matter.

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Leases Where We are Lessee

We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Lease expense is charged to operating expenses on a straight-line basis over the period of expected benefit. Contingent rental payments are expensed as incurred. Total rental expense for the years ended December 31, 2009, 2008 and 2007 was $21.2 million, $20.2 million and $11.7 million, respectively. The following table presents minimum lease payment obligations under our operating leases with terms in excess of one year for the years ending December 31:

	Office space and other (1)	**Land Leases** (2)	**Total**
2010	$ 1,528	$ 2,945	$ 4,473
2011	1,536	3,059	4,595
2012	1,539	3,282	4,821
2013	1,563	3,409	4,972
2014	1,615	3,542	5,157
Thereafter	11,197	295,510	306,707
Total	$ 18,978	$ 311,747	$ 330,725

(1) We lease certain other land and space in office buildings.

(2) We have leases for subsurface underground gas storage rights and surface rights in connection with our operations in the Natural Gas Storage segment. We may cancel these leases if the storage reservoir is not used for underground storage of natural gas or the removal or

injection thereof for a continuous period of two consecutive years. Lease expense associated with these leases is being recognized on a straight-line basis over 44 years. For the years ended December 31, 2009 and 2008, the Natural Gas Storage segment s lease expense was approximately $7.4 million and $7.1 million, respectively. At December 31, 2009 and 2008, $4.5 million and $4.6 million, respectively, was recorded as an increase in our deferred lease liability. We estimate that the deferred lease liability will continue to increase through 2032, at which time our deferred lease liability is estimated to be approximately $64.7 million. Our deferred lease liability will then be reduced over the remaining 19 years of the lease, since the expected annual lease payments will exceed the amount of lease expense.

Leases Where We are Lessor

We have entered into capacity leases with remaining terms from 5 to 13 years that are accounted for as operating leases. All of the agreements provide for negotiated extensions. Future minimum lease payments to be received under such operating leasing arrangements as of December 31, 2009 are as follows:

	Years Ending December 31,
2010	$ 8,839
2011	8,839
2012	8,839
2013	8,839
2014	6,819
Thereafter	48,446
Total	$ 90,621

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6. INVENTORIES

Our inventory amounts were as follows at the dates indicated:

	December 31, 2009	December 31, 2008
Refined petroleum products (1)	$ 299,473	$ 69,568
Materials and supplies	10,741	14,661
Total inventories	$ 310,214	$ 84,229

(1) Ending inventory was 141.7 million and 47.7 million gallons of refined petroleum products at December 31, 2009 and 2008, respectively.

At December 31, 2009 and 2008, approximately 99% and 78%, respectively, of our inventory was hedged. Hedged inventory is valued at current market prices with the change in value of the inventory reflected in the consolidated statements of operations. At December 31, 2009 and 2008, 0% and 17%, respectively, of our inventory was committed against fixed-priced sales contracts and such inventory was valued at the lower of cost or market.

7. PREPAID AND OTHER CURRENT ASSETS

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

	December 31, 2009	December 31, 2008
Prepaid insurance	$ 6,916	$ 7,112
Insurance receivables	13,544	5,101
Ammonia receivable	7,429	12,058
Margin deposits	21,037	32,345
Prepaid services	21,571	
Unbilled revenue	13,201	1,074
Tax receivable	7,162	
Other	12,831	14,421
Total prepaid and other current assets	$ 103,691	$ 72,111

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8. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following at the dates indicated:

	December 31, 2009	December 31, 2008
Land	$ 64,712	$ 62,139
Rights-of-way	97,309	97,724
Pad gas	29,346	29,346
Buildings and leasehold improvements	103,535	92,668
Machinery, equipment and office furnishings	2,120,092	1,998,903
Construction in progress	78,363	173,691
Total property, plant and equipment	2,493,357	2,454,471
Less: Accumulated depreciation	(265,092)	(223,150)
Total property, plant and equipment, net	$ 2,228,265	$ 2,231,321

Depreciation expense was $50.7 million, $47.2 million and $39.4 million for the years ended December 2009, 2008 and 2007, respectively.

Impairment of Long-Lived Assets and Assets Held for Sale

We owned and operated an approximately 350-mile natural gas liquids pipeline (the Buckeye NGL Pipeline) that runs from Wattenberg, Colorado to Bushton, Kansas. During the second quarter of 2009, we received notification that several of our shippers, which were then using the Buckeye NGL Pipeline, intended to migrate their business to a competing pipeline that recently went into service. In connection with this notification, there was a significant decline in shipment volumes as compared to historical averages. This significant loss in the customer base utilizing our NGL pipeline, in conjunction with the authorization of the Board of Directors of Buckeye GP to pursue the sale of Buckeye NGL Pipe Lines LLC (Buckeye NGL), the entity which owned the Buckeye NGL Pipeline, triggered an evaluation of a potential asset impairment that resulted in a non-cash charge to earnings in the second quarter of 2009 of $72.5 million in the Pipeline Operations segment.

We ceased depreciation of the assets as of July 1, 2009 and reclassified the assets of Buckeye NGL to Assets held for sale on the December 31, 2009 consolidated balance sheet. Effective January 1, 2010, we sold our ownership interest in Buckeye NGL for $22.0 million. The sales proceeds exceeded the previously impaired carrying value of the Buckeye NGL Pipeline by $12.8 million, resulting in the reversal of $12.8 million of the previously recorded asset impairment expense in the fourth quarter of 2009, yielding a net impairment of $59.7 million for the year ended December 31, 2009. This impairment and the reversal are reflected within the category Asset Impairment Expense on our consolidated statements of operations.

The carrying amounts of the major classes of assets held for sale by Buckeye NGL at December 31, 2009 were as follows:

Inventories	$ 629
Property, plant and equipment, net	21,371
Assets held for sale	$ 22,000

Revenues for Buckeye NGL for the year ended December 31, 2009 were $9.3 million.

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AROs

The following table presents information regarding our AROs:

ARO liability balance, January 1, 2008	$
Liabilities assumed with Lodi Gas acquisition	665
Additional ARO for Kirby Hills Phase II	194
Accretion expense	60
ARO liability balance, December 31, 2008	919
Accretion expense	101
ARO liability balance, December 31, 2009 (1)	$ 1,020

(1) Amount is included in other non-current liabilities.

9. 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:

		December 31,	
	Ownership	**2009**	**2008**
Muskegon Pipeline LLC	40.0%	$ 15,273	$ 14,967
Transport4, LLC	25.0%	379	332
West Shore Pipe Line Company	24.9%	30,320	30,340
West Texas LPG Pipeline Limited Partnership	20.0%	50,879	44,471
Total equity investments		$ 96,851	$ 90,110

During the years ended December 31, 2009, 2008 and 2007, we invested an additional $3.9 million, $9.8 million and $0.9 million, respectively, in West Texas LPG Pipeline Limited Partnership (WT LPG) as our pro-rata contribution for an expansion project that was required to meet increased pipeline demand caused by increased product production in the Fort Worth basin and East Texas regions. The expansion project consists of the construction of 39 miles of 12-inch pipeline and installation of multiple booster stations. The WT LPG expansion project became operational in February 2009. Affiliates of Chevron Corporation own the remaining 80% interest in, and operate, WT LPG.

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

	Year Ended December 31,		
	2009	**2008**	**2007**
Muskegon Pipeline LLC	$ 1,437	$ 1,367	$ 1,385
Transport4, LLC	147	70	43
West Shore Pipe Line Company	4,809	3,133	3,511

WT LPG	6,138	3,418	2,614
Total earnings from equity investments	$ 12,531	$ 7,988	$ 7,553

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10. GOODWILL AND INTANGIBLE ASSETS

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the amounts assigned to assets acquired and liabilities assumed in the transaction. Goodwill is not amortized; however, it is subject to annual impairment testing. The following table summarizes our goodwill amounts by segment at the dates indicated:

	December 31,	
	2009	**2008**
Terminalling and Storage:		
Acquisition of six terminals in June 2000	$ 11,355	$ 11,355
Acquisition of Albany Terminal in 2008 (1)	26,829	28,597
Subtotal	38,184	39,952
Natural Gas Storage:		
Acquisition of Lodi Gas in 2008	169,560	169,560
Energy Services:		
Acquisition of Farm & Home in 2008	1,132	1,132
Total goodwill	$ 208,876	$ 210,644

(1) Goodwill decreased by $1.8 million as of December 31, 2009 from December 31, 2008 due to the finalization of the purchase price allocation of the Albany Terminal; the difference was allocated to property, plant and equipment.

Intangible Assets

Intangible assets include customer relationships and contracts. These intangible assets have definite lives and are being amortized on a straight-line basis over their estimated useful lives ranging from 5 to 25 years. The weighted average useful life of intangible assets is 14 years. Our amortizable customer contracts are contracts that were acquired in connection with the acquisition of BGC in March 1999, the acquisition of the Taylor, Michigan terminal in December 2005 and the acquisition of certain pipeline and terminal assets from ConocoPhillips in November 2009. The customer contracts are being amortized over their contractual life, 5 years in the case of the acquisition of certain pipeline and terminal assets from ConocoPhillips. The customer relationships resulted from the acquisition of Farm & Home (see Note 4 for further discussion). We determined, through an analysis of historical customer attrition rates at

Farm & Home, that an appropriate recovery period for customer relationships is approximately 12 years. Intangible assets consist of the following at the dates indicated:

	December 31, 2009	December 31, 2008
Customer relationships	$ 38,300	$ 38,300
Accumulated amortization	(5,631)	(2,662)
Net carrying amount	32,669	35,638
Customer contracts	16,380	11,800
Accumulated amortization	(3,892)	(3,324)
Net carrying amount	12,488	8,476
Total intangible assets	$ 45,157	$ 44,114

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For the years ended December 31, 2009, 2008, and 2007, amortization expense related to intangible assets was $3.5 million, $3.2 million and $0.5 million, respectively. Amortization expense related to intangible assets is expected to be approximately $4.8 million for each of the next five years.

11. OTHER NON-CURRENT ASSETS

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

	December 31, 2009	December 31, 2008
Deferred charge, net (1)	$ 6,024	$ 10,721
Prepaid services	11,640	
Long-term derivative assets	17,204	6,273
Debt issuance costs	11,058	8,944
Insurance receivables	7,265	6,518
Other	9,586	11,737
Total other non-current assets	$ 62,777	$ 44,193

(1) Net of accumulated amortization of $58.2 million and $53.5 million at December 31, 2009 and 2008, 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 the straight-line basis over 13.5 years (see Note 19 for

further
discussion).

12. ACCRUED AND OTHER CURRENT LIABILITIES

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

	December 31, 2009	December 31, 2008
Taxes other than income	$ 15,381	$ 13,555
Accrued charges due Buckeye GP	1,218	1,493
Accrued charges due Services Company	6,104	4,028
Accrued employee benefit liability	3,287	2,297
Environmental liabilities	10,799	12,337
Accrued interest	30,609	25,547
Payable for ammonia purchase	7,015	9,373
Unearned revenue	6,829	12,186
Accrued capital expenditures	1,611	4,902
Reorganization	2,133	
Deferred consideration	1,675	
Other	20,082	20,072
Total accrued and other current liabilities	$ 106,743	$ 105,790

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13. DEBT OBLIGATIONS

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

	December 31, 2009	December 31, 2008
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	
6.750% Notes due August 15, 2033 (1)	150,000	150,000
Credit Facility	78,000	298,267
BES Credit Agreement	239,800	96,000
Less: Unamortized discount	(4,854)	(3,604)
Adjustment to fair value associated with hedge of fair value	824	1,059
Subtotal debt	1,738,770	1,541,722
Less: Current portion of long-term debt	(239,800)	(96,000)
Total long-term debt	$ 1,498,970	$ 1,445,722

(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 following table presents the scheduled maturities of principal amounts of our debt obligations for the next five years and in total thereafter:

	Years Ending December 31,
2010	$ 239,800
2011	

2012	78,000
2013	300,000
2014	275,000
Thereafter	850,000
Total	$ 1,742,800

The fair values of our aggregate debt and credit facilities were estimated to be $1,762.1 million and $1,367.7 million at December 31, 2009 and 2008, respectively. The fair values of the fixed-rate debt at December 31, 2009 and 2008 were estimated by market-observed 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 rate.

On August 18, 2009, we sold $275.0 million aggregate principal amount of 5.500% Notes due 2019 (the 5.500% Notes) in an underwritten public offering. The notes were issued at 99.35% of their principal amount. Total proceeds from this offering, after underwriters fees, expenses and debt issuance costs of $1.8 million, were approximately $271.4 million and were used to reduce amounts outstanding under our credit facility and for working capital purposes.

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On January 11, 2008, we sold $300.0 million aggregate principal amount of 6.050% Notes due 2018 (the 6.050% Notes) in an underwritten public offering. Proceeds from this offering, after underwriters fees and expenses, were approximately $298.0 million and were used to partially pre-fund the Lodi Gas acquisition. In connection with this debt offering, we settled two forward-starting interest rates swaps (see Note 16), which resulted in a settlement payment of $9.6 million that is being amortized as interest expense over the ten-year term of the 6.050% Notes.

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 and Moody s Investor Services for our senior unsecured non-credit enhanced long-term debt. At December 31, 2009 and 2008, $78.0 million and $298.3 million, respectively, was outstanding under the Credit Facility. The weighted average interest rate for borrowings outstanding under the Credit Facility was 0.6% at December 31, 2009.

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 December 31, 2009, our Funded Debt Ratio was approximately 4.4 to 1.00. As permitted by the Credit Facility, the $239.8 million of borrowings by BES under its separate credit agreement (discussed below) and the $59.7 million impairment of Buckeye NGL (see Note 8) were excluded from the calculation of the Funded Debt Ratio.

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 December 31, 2009, we were not aware of any instances of noncompliance with the covenants under our Credit Facility.

On August 21, 2009, Buckeye Energy Holdings LLC (BEH), our wholly owned subsidiary, bought the outstanding loans and commitments of Aurora Bank FSB (formerly Lehman Brother Bank, FSB), a lender under the Credit Facility, through a sale and assignment agreement. Concurrent with this transaction, we repaid the $213.5 million outstanding balance of the Credit Facility, plus accrued interest and fees. The Credit Facility was subsequently amended to remove BEH as a lender by terminating its commitment in full, thus reducing the borrowing capacity of the Credit Facility from $600.0 million to $580.0 million and the expansion option amount from $800.0 million to $780.0 million.

At December 31, 2009 and 2008, we had committed $1.4 million and $1.3 million in support of letters of credit, respectively. The obligations for letters of credit are not reflected as debt on our consolidated balance sheets.

BES Credit Agreement

BES has a credit agreement (the BES Credit Agreement) that, prior to August 2009, provided for borrowings of up to $175.0 million. In August 2009, the BES Credit Agreement was amended to provide for total borrowings of up to $250.0 million. 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)

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plus 1.75%, (ii) the Eurodollar Rate (as defined in the BES Credit Agreement) plus 1.75% or (iii) the Base Rate (as defined in the BES Credit Agreement) plus 0.25%. 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 $239.8 million and $96.0 million at December 31, 2009 and 2008, respectively, all of which were classified as current liabilities. 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

At December 31, 2009, BES s Consolidated Tangible Net Worth and Consolidated Net Working Capital were $126.1 million and $78.2 million, respectively, and the Consolidated Leverage Ratio was 2.6 to 1.0. The weighted average interest rate for borrowings outstanding under the BES Credit Agreement was 2.0% at December 31, 2009.

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 December 31, 2009, we were not aware of any instances of noncompliance with the covenants under the BES Credit Agreement.

14. OTHER NON-CURRENT LIABILITIES

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

	December 31, 2009	December 31, 2008
Accrued employee benefit liabilities (see Note 17)	$ 45,837	$ 49,281
Accrued environmental liabilities	19,053	14,684
Deferred consideration	18,425	20,100
Deferred rent	9,158	4,658
Other	10,378	11,979
Total other non-current liabilities	$ 102,851	$ 100,702

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15. ACCUMULATED OTHER COMPREHENSIVE LOSS

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

	December 31, 2009	December 31, 2008
Adjustments to funded status of retirement income guarantee plan and retiree medical plan	$ (4,453)	$ (5,530)
Amortization of interest rate swap	(7,753)	(8,714)
Derivative instruments	17,501	(221)
Accumulated amortization of retirement income guarantee plan and retiree medical plan	(6,142)	(4,502)
Total accumulated other comprehensive loss	$ (847)	$ (18,967)

In connection with our reorganization, $6.4 million of the aggregate expense of $32.1 million was recorded as an adjustment to the funded status of the retirement income guarantee plan and the retiree medical plan (see Note 17).

16. 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.

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 manage a portion of our interest rate exposure by utilizing interest rate swaps to effectively convert a portion of our variable-rate debt into fixed-rate debt. In addition, 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,

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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, 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 an existing debt obligation.

In October 2008, January 2009 and April 2009, we entered into interest rate swap agreements for notional amounts of $50.0 million each to hedge our variable interest rate risk with respect to borrowings under the Credit Facility. Under each swap agreement, we paid a fixed rate of interest of 3.15%, 0.81% and 0.63%, respectively, for 180 days and, in exchange, received a series of six monthly payments calculated based on the 30-day LIBOR rate in effect at the beginning of each monthly period. The amounts we received corresponded to the 30-day LIBOR rates that we paid on the respective $50.0 million borrowed under the Credit Facility. We designated all of the swap agreements as cash flow hedges, and changes in value between the trade date and the designation date were recognized in earnings. The October 2008 swap settled on April 20, 2009, and the January 2009 swap settled on July 28, 2009. On August 27, 2009, in conjunction with the repayment of the outstanding balance under the Credit Facility, the April 2009 swap was terminated.

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. 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. Unrealized gains of $17.2 million were recorded in accumulated other comprehensive income (loss) to reflect the change in the fair values of the forward-starting interest rate swaps as of December 31, 2009. 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.

In January 2008, we terminated two forward-starting interest rate swap agreements associated with the 6.050% Notes and made a payment of $9.6 million in connection with the termination. We have recorded the amount in other comprehensive income and are amortizing the amount of the payment into interest expense over the ten-year term of the 6.050% Notes. Over the next twelve months, we expect to reclassify $1.0 million of accumulated other comprehensive loss that was generated by these interest rate swap agreements as an increase to interest expense.

Commodity Derivatives

Our Energy Services segment primarily uses exchange-traded refined petroleum product futures contracts to manage the risk of market price volatility on its refined petroleum product inventories and its fixed-price sales contracts. The derivative contracts used to hedge refined petroleum product inventories are designated as fair value hedges. Accordingly, our method of measuring ineffectiveness compares the change in the fair value of New York Mercantile Exchange (NYMEX) futures contracts to the change in fair value of our hedged fuel inventory. 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 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 (January 2010 through July 2011) for a price of $5.47 per million British thermal unit (MMBtu). We designated the futures contract as a cash flow hedge at inception.

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Unrealized gains of $0.3 million were recorded in accumulated other comprehensive income (loss) to reflect the change in the fair values of the contract as of December 31, 2009.

The following table summarizes our commodity derivative instruments outstanding at December 31, 2009 (amounts in thousands of gallons, except as noted):

Derivative Purpose	Volume (1) Current	Long-Term (2)	Accounting Treatment
Derivatives NOT designated as hedging instruments:			
Fixed-price sales contracts	33,428		Mark-to-market
Futures contracts for fixed-price sales contracts	21,000		Mark-to-market
Derivatives designated as hedging instruments:			
Futures contracts for inventory	132,090		Fair Value Hedge
Futures contract for natural gas (MMBtu)	360,000	210,000	Cash Flow Hedge

(1) Volume represents net notional position.

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

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

	December 31, 2009 Assets Fair value	(Liabilities) Fair value	Derivative Net Carrying Value
Derivatives NOT designated as hedging instruments:			
Fixed-price sales contracts	$ 4,959	$ (3,662)	$ 1,297
Futures contracts for fixed-price sales contracts	7,594	(384)	7,210
Derivatives designated as hedging instruments:			
Futures contracts for inventory	$ 1,992	$ (20,517)	$ (18,525)
Futures contract for natural gas	312		312
Interest rate contracts	17,204		17,204

Total	$	7,498

Balance Sheet Locations:	December 31, 2009
Derivative assets	$ 4,959
Other non-current assets	17,204
Derivative liabilities	(14,665)
Total	$ 7,498

Substantially all of the unrealized net loss of $18.5 million at December 31, 2009 for inventory hedges represented by futures contracts will be realized by the second quarter of 2010 as the related inventory is sold. Gains recorded on inventory hedges that were ineffective were approximately $2.6 million for the year ended December 31, 2009. As of December 31, 2009, open refined petroleum product derivative contracts (represented by

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the fixed-price sales contracts and futures contracts for fixed-price sales contracts noted above) varied in duration, but did not extend beyond December 2010. In addition, at December 31, 2009, we had refined petroleum product inventories which we intend to use to satisfy a portion of the fixed-price sales contracts.

The gains and losses on our derivative instruments recognized in income, 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 year ended December 31, 2009:

Derivatives NOT designated as hedging instruments	**Location**	**Gain (Loss) Recognized in Income on Derivatives**
Fixed-price sales contracts	Product sales	$ (6,881)
Futures contracts for fixed-price sales contracts	Cost of product sales and natural gas storage services	15,653

Derivatives designated as hedging instruments	**Location**	
Futures contracts for inventory	Cost of product sales and natural gas storage services	$ (47,012)
Futures contract for natural gas	Cost of product sales and natural gas storage services	(3)
Interest rate contracts	Interest and debt expense	(224)

Derivatives designated as hedging instruments	**Gain (Loss) Reclassified from AOCI to Income**		**Change in Value Recognized in OCI on Derivatives**
	Location	**Amount**	
Futures contract for natural gas	Cost of product sales and natural gas storage services	$ (409)	$ 296
Interest rate contracts	Interest and debt expense	(218)	17,204

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.

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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.

Recurring

The following table sets forth financial assets and liabilities, measured at fair value on a recurring basis, as of the measurement dates, December 31, 2009 and 2008, and the basis for that measurement, by level within the fair value hierarchy:

	December 31, 2009		December 31, 2008	
	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:				
Commodity derivatives	$	$ 4,959	$ 25,225	$ 79,322
Asset held in trust	1,793		3,648	
Interest rate derivatives		17,204		
Financial liabilities:				
Interest rate derivatives				(333)

Commodity derivatives	(11,003)	(3,662)	(50,806)	(1,045)
Total	$ (9,210)	$ 18,501	$ (21,933)	$ 77,944

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The value of the Level 1 commodity 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 commodity 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 derivative was based on observable market data related to similar obligations.

The commodity derivative assets of $5.0 million and $79.3 million as of December 31, 2009 and 2008, respectively, are net of a credit valuation adjustment (CVA) of ($0.9) million and ($0.6) 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.

Non-Recurring

Certain nonfinancial assets and liabilities are measured at fair value on a nonrecurring basis and are subject to fair value adjustments in certain circumstances, such as when there is evidence of possible impairment. The following table presents the fair value of an asset carried on the 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 year ended December 31, 2009:

	December 31, 2009	Level 1	Level 2	Level 3	Total Losses
Assets held for sale (1)	$22,000	$22,000	$	$	$59,724

(1) Represents inventory and property, plant and equipment included in assets held for sale (see Note 8).

As a result of a loss in the customer base utilizing our NGL pipeline, we recorded a non-cash impairment charge of $59.7 million during the year ended December 31, 2009. The estimated fair value was based on the proceeds from the sale of our ownership interest in Buckeye NGL in January 2010.

17. PENSIONS AND OTHER POSTRETIREMENT BENEFITS

RIGP and Retiree Medical Plan

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.

In addition, Services Company 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.

Pursuant to the previously mentioned VERP and involuntary reduction in workforce (see Note 3), we recognized a settlement in the RIGP of approximately $14.0 million for the year ended December 31, 2009 as a

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result of participants in the RIGP receiving lump sum benefit payments. In addition, we recorded a curtailment in the Retiree Medical Plan of approximately $1.1 million for the year ended December 31, 2009 as a result of certain participants affected by the VERP and involuntary reduction in workforce being eligible for benefits under the Retiree Medical Plan.

Certain employees who were eligible for RIGP benefits retired in 2008. The RIGP provides an option for the retiree to elect a calculated lump sum payment, rather than a retirement annuity, after the participant s retirement date. The RIGP recognizes pension settlements when payments exceed the sum of service and interest cost components of net periodic pension cost for the plan for the fiscal year. The RIGP settled about 10% of the unrecognized losses related to these lump sum payments which resulted in a one-time charge of $1.4 million.

The following table provides a reconciliation of projected benefit obligations, plan assets and the funded status of the RIGP and the Retiree Medical Plan for the periods indicated:

	RIGP Year Ended December 31,		Retiree Medical Plan Year Ended December 31,	
	2009	**2008**	**2009**	**2008**
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 27,134	$ 20,240	$ 34,877	$ 36,663
Service cost	495	723	339	382
Interest cost	1,182	1,018	1,941	1,947
Plan participants contributions			295	
Part D reimbursement			245	
Actuarial loss (gain)	4,399	8,299	(964)	(2,669)
Curtailments			1,091	
Settlements	(13,977)	(2,990)		
Benefit payments	(130)	(156)	(2,375)	(1,446)
Benefit obligation at end of year	$ 19,103	$ 27,134	$ 35,449	$ 34,877
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 10,433	$ 12,915	$	$
Actual return on plan assets	(358)	(189)		
Plan participants contributions			295	
Part D reimbursement			245	
Employer contribution	9,459	853	1,835	1,446
Settlements	(13,977)	(2,990)		
Benefits paid	(130)	(156)	(2,375)	(1,446)
Fair value of plan assets at end of year	$ 5,427	$ 10,433	$	$
Funded status at end of year	$ (13,676)	$ (16,701)	$ (35,449)	$ (34,877)

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Amounts recognized in our consolidated balance sheets consist of the following at the dates indicated:

	RIGP December 31, 2009	RIGP December 31, 2008	Retiree Medical Plan December 31, 2009	Retiree Medical Plan December 31, 2008
Liabilities:				
Accrued employee benefit liabilities current	$	$	$ 3,287	$ 2,297
Accrued employee benefit liabilities noncurrent	$ 13,676	$ 16,701	$ 32,162	$ 32,580
Accumulated other comprehensive (income) loss:				
Net actuarial loss	$ 9,416	$ 12,437	$ 11,508	$ 13,488
Prior service credit	(46)	(531)	(10,283)	(15,362)
Total	$ 9,370	$ 11,906	$ 1,225	$ (1,874)

Information regarding the accumulated benefit obligation in excess of plan assets for the RIGP is as follows at the dates indicated:

	RIGP December 31, 2009	RIGP December 31, 2008
Projected benefit obligation	$19,103	$27,134
Accumulated benefit obligation	13,156	16,112
Fair value of plan assets	5,427	10,433

The assumptions used in determining net benefit cost for the RIGP and the Retiree Medical Plan were as follows for the periods indicated:

	RIGP 2009	RIGP 2008	RIGP 2007	Retiree Medical Plan 2009	Retiree Medical Plan 2008	Retiree Medical Plan 2007
Weighted average expense assumption for the years ended December 31:						
Discount rate	5.5%	5.5%	5.7%	5.8%	5.8%	6.0%
Expected return on plan assets	7.5%	8.5%	8.5%	N/A	N/A	N/A
Rate of compensation increase	4.0%	4.0%	4.0%	N/A	N/A	N/A

The assumptions used in determining net benefit liabilities for the RIGP and the Retiree Medical Plan were as follows for the periods indicated:

	RIGP 2009	RIGP 2008	Retiree Medical Plan 2009	Retiree Medical Plan 2008
Weighted average balance sheet assumptions as of December 31:				
Discount rate	5.5%	5.5%	5.8%	5.8%
Rate of compensation increase	4.0%	4.0%	N/A	N/A

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The expected return on plan assets was determined by a review of projected future returns along with historical returns of portfolios with similar investments as those in the plan.

The assumed annual rate of increase in the per capital cost of covered health care benefits as of December 31, 2009 in the Retiree Medical Plan was 8.5% for 2010, decreasing each year to a rate of 5.0% in 2017 and thereafter.

Assumed healthcare cost trend rates may have a significant effect on the amounts reported for the Retiree Medical Plan. To illustrate, increasing or decreasing the assumed health care cost trend rates by one percentage point for each future year would have had the following effects on 2009 results:

	1% Increase	1% (Decrease)
Effect on total service cost and interest cost components	$ 108	$ (96)
Effect on postretirement benefit obligation	1,262	(1,130)

The components of the net periodic benefit cost and other amounts recognized in OCI for the RIGP and the Retiree Medical Plan were as follows for the periods indicated:

	RIGP Year Ended December 31,			Retiree Medical Plan Year Ended December 31,		
	2009	2008	2007	2009	2008	2007
Components of net periodic benefit cost:						
Service cost	$ 495	$ 723	$ 808	$ 339	$ 382	$ 669
Interest cost	1,182	1,018	1,034	1,941	1,947	2,113
Expected return on plan assets	(570)	(1,030)	(864)			
Recognized gain due to curtailments				(749)		
Amortization of prior service cost benefit	(485)	(454)	(454)	(3,240)	(3,438)	(3,438)
Actuarial loss due to settlements	7,280	1,371				
Amortization of unrecognized losses	1,069	296	534	1,016	1,023	1,429
Net periodic benefit costs	$ 8,971	$ 1,924	$ 1,058	$ (693)	$ (86)	$ 773
Other changes in plan assets and benefit obligations recognized in OCI:						
Net actuarial loss (gain)	$ 5,328	$ 9,517	$ (158)	$ 875	$ (2,669)	$ 996
Amortization of net actuarial gain	(1,069)	(296)	(534)	(1,016)	(1,023)	(1,429)
Actuarial loss due to settlements	(7,280)	(1,371)				
Amortization of prior service cost	485	454	454	3,240	3,438	3,438
Total recognized in OCI	$ (2,536)	$ 8,304	$ (238)	$ 3,099	$ (254)	$ 3,005
Total recognized in net period benefit cost and OCI	$ 6,435	$ 10,228	$ 820	$ 2,406	$ (340)	$ 3,778

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During the year ended December 31, 2010, we expect that the following amounts currently included in OCI will be recognized in our consolidated statement of operations:

	RIGP	Retiree Medical Plan
Amortization of unrecognized losses	$1,040	$ 894
Amortization of prior service cost benefit	(45)	(2,964)

We estimate the following benefit payments, which reflect expected future service, as appropriate, will be paid in the years indicated:

	RIGP	Retiree Medical Plan
2010	$3,650	$ 3,381
2011	1,229	2,757
2012	1,448	2,785
2013	1,361	2,858
2014	1,409	2,890
Thereafter	9,252	14,329

A minimum funding contribution is not required to be made to the RIGP during 2010. Funding requirements for subsequent years are uncertain and will depend on whether there are any changes in the actuarial assumptions used to calculate plan funding levels, the actual return on plan assets and any legislative or regulatory changes affecting plan funding requirements. For tax planning, financial planning, cash flow management or cost reduction purposes, we may increase, accelerate, decrease or delay contributions to the plan to the extent permitted by law.

We do not fund the Retiree Medical Plan and, accordingly, no assets are invested in the plan. A summary of investments in the RIGP are as follows at December 31, 2009:

	Quoted Prices in Active Markets (Level 1)	Unobservable Inputs (Level 3)
Mutual fund equity securities (1)	$ 1,701	$
Mutual fund money market	162	
Coal lease (2)		3,564
Fair value of plan assets at end of year	$ 1,863	$ 3,564

(1) This mutual fund generally seeks long-term growth of capital and income and invests in a diversified

portfolio consisting of approximately 80% in equities and the remainder in income-providing securities, such as preferred stocks, high-grade bonds or money market securities.

(2) This value was determined using an expected present value of future cash flows valuation model. This plan asset relates to a 20.8% interest in a coal lease, which derives value from specified minimum royalty payments received from CONSOL Energy Inc. related to coal reserves mined from two Pennsylvania mines owned by the lessor. The coal lease extends through 2023.

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The following table summarizes the activity in our Level 3 pension assets during the year ended December 31, 2009:

	Coal Lease
Beginning balance, January 1, 2009	$ 4,365
Lease payments received	381
Unrealized loss	(801)
Transfers out of Level 3	(381)
Ending balance, December 31, 2009	$ 3,564

The RIGP investment policy does not target specific asset classes, but seeks to balance the preservation and growth of capital in the plan s mutual fund investments with the income derived with proceeds from the coal lease. While no significant changes in the asset allocation of the plan are expected during the upcoming year, Services Company may make changes at any time.

Retirement and Savings Plan

Services Company also sponsors a retirement and savings plan (the Retirement and Savings Plan) through which it provides retirement benefits for substantially all of its regular full-time employees, except those covered by certain labor contracts. The Retirement and Savings Plan consists of two components. Under the first component, Services Company contributes 5% of each eligible employee s covered salary to an employee s separate account maintained in the Retirement and Savings Plan. Under the second component, for all employees not participating in the ESOP, Services Company makes a matching contribution into the employee s separate account for 100% of an employee s contribution to the Retirement and Savings Plan up to 6% of an employee s eligible covered salary. For Services Company employees who participate in the ESOP, Services Company does not make a matching contribution. Total costs of the Retirement and Savings Plan were approximately $7.1 million, $5.6 million and $4.6 million during the years ended December 31, 2009, 2008 and 2007, respectively.

Services Company also participates in a multi-employer retirement income plan that provides benefits to employees covered by certain labor contracts. Pension expense for the plan was $0.3 million, $0.2 million and $0.2 million during the years ended December 31, 2009, 2008 and 2007, respectively.

In addition, Services Company contributes to a multi-employer postretirement benefit plan that provides health care and life insurance benefits to employees covered by certain labor contracts. The cost of providing these benefits was approximately $0.2 million during each of the years ended December 31, 2009, 2008 and 2007.

18. UNIT-BASED COMPENSATION PLANS

Long-Term Incentive Plan

On March 20, 2009, our 2009 LTIP became effective. The 2009 LTIP, which is administered by the Compensation Committee of the Board of Directors of Buckeye GP (the Compensation Committee), provides for the grant of phantom units, performance units and in certain cases, distribution equivalent rights (DERs) which provide the participant a right to receive payments based on distributions we make on our LP Units. Phantom units are notional LP Units whose vesting is subject to service-based restrictions or other conditions established by the Compensation Committee in its discretion. Phantom units entitle a participant to receive an LP Unit, without payment of an exercise price, upon vesting. Performance units are notional LP Units whose vesting is subject to the attainment of one or more performance goals, and which entitle a participant to receive LP Units without payment of an exercise price upon vesting. DERs are rights to receive a cash payment per phantom unit or performance unit, as applicable, equal to the per unit cash distribution we pay on our LP Units.

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The number of LP Units that may be granted under the 2009 LTIP may not exceed 1,500,000, subject to certain adjustments. The number of LP Units that may be granted to any one individual in a calendar year will not exceed 100,000. If awards are forfeited, terminated or otherwise not paid in full, the LP Units underlying such awards will again be available for purposes of the 2009 LTIP. Persons eligible to receive grants under the 2009 LTIP are (i) officers and employees of Buckeye GP and any of our affiliates who provide services to us and (ii) independent members of the Board of Directors of Buckeye GP or of MainLine Management LLC (MainLine Management), the general partner of BGH. Phantom units or performance units may be granted to participants at any time as determined by the Compensation Committee.

The fair values of both the performance unit and phantom unit grants are based on the average market price of our LP Units on the date of grant. Compensation expense equal to the fair value of those performance unit and phantom unit awards that actually vest is estimated and recorded over the period the grants are earned, which is the vesting period. Compensation expense estimates are updated periodically. The vesting of the performance unit awards is also contingent upon the attainment of predetermined performance goals, which, depending on the level of attainment, could increase or decrease the value of the awards at settlement. Quarterly distributions paid on DERs associated with phantom units are recorded as a reduction of our Limited Partners Capital on the consolidated balance sheets.

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 2009 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 phantom units will be granted in 2010.

2009 LTIP Awards

During the year ended December 31, 2009, the Compensation Committee granted 47,108 phantom units to employees, 18,000 phantom units to independent directors, and 94,532 performance units to employees. The vesting period for the phantom units is one year or three years of service for grants to directors or employees, respectively. The vesting criteria for the performance units are the attainment of a performance goal, defined in the award agreements as distributable cash flow per unit , during the third year of a three-year period and remaining employed throughout three-year period.

Phantom unit grantees will be paid quarterly distributions on DERs associated with phantom units over their respective vesting periods of one-year or three-years in the same amounts per phantom unit as distributions paid on our LP Units over those same one-year or three-year periods. The amount paid with respect to phantom unit distributions was $0.1 million for the year ended December 31, 2009. Distributions may be paid on performance units at the end of the three year vesting period. In such case, DERs will be paid on the number of LP Units for which the performance units will be settled.

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The following table sets forth the 2009 LTIP activity for the year ended December 31, 2009:

	Number of LP Units	Weighted Average Grant Date Fair Value per LP Unit(1)	Total Value
Unvested at January 1, 2009		$	$
Granted	159,640	39.72	6,340
Vested	(519)	39.06	(20)
Forfeited	(19,026)	39.06	(743)
Unvested at December 31, 2009	140,095	$ 39.81	$ 5,577

(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 December 31, 2009, approximately $4.1 million of compensation expense related to the 2009 LTIP is expected to be recognized over a weighted average period of approximately 1.9 years.

Option Plan

We also sponsor the Option Plan pursuant to which we historically granted options to employees to purchase LP Units at the market price of our LP Units on the date of grant. Generally, the options vest three years from the date of grant and expire ten years from the date of grant. As unit options are exercised, we issue new LP Units to the holder. We have not historically repurchased, and do not expect to repurchase in 2010, any of our LP Units.

For the retirement eligibility provisions of the Option Plan, we follow the non-substantive vesting method and recognize compensation expense immediately for options granted to retirement-eligible employees, or over the period from the grant date to the date retirement eligibility is achieved. Unit-based compensation expense recognized in the consolidated statements of operations for the year ended December 31, 2009 is based upon options ultimately expected to vest. Forfeitures have been estimated at the time of grant and will be revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. Forfeitures were estimated based upon historical experience.

Generally, compensation expense is recognized based on the fair value on the date of grant estimated using a Black-Scholes option pricing model. We recognize compensation expense for these awards granted on a straight-line basis over the requisite service period. Compensation expense is based on options ultimately expected to vest by estimating forfeitures at the date of grant based upon historical experience and revising those estimates, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

Due to regulations adopted under Internal Revenue Code Section 409A, holders of options granted during 2008 would have been subject to certain adverse tax consequences if the terms of the grant were not modified. We received the approval of the holders of options granted in 2008 to shorten the term of those options to avoid the adverse tax consequences under Section 409A. Options granted before January 1, 2008 were not impacted by the IRS regulations. This modification did not have a material impact on our financial results. Following the adoption of the 2009 LTIP on March 20, 2009, we ceased making additional grants under the Option Plan.

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The fair value of unit options granted to employees was estimated using the Black-Scholes option pricing model with the following assumptions for the periods indicated:

	Year Ended December 31,	
	2008	**2007**
Expected dividend yield	6.3%	6.6%
Expected unit price volatility	16.0%	19.6%
Risk-Free interest rate	2.7%	4.7%
Expected life (in years)	4.8	6.5
Weighted-average fair value at grant date	$ 2.89	$ 5.07

The expected dividend yield in 2008 was based on 4.8 years of historic yields of LP Units. The expected volatility was based upon 4.8 years of historical volatility of our LP Units. For 2007, we used the simplified method to calculate the expected life, which was the option vesting period of three years plus the option term of ten years divided by two. For 2008, we used historical experience in determining the expected life assumption used to value our options. The risk-free interest rate is calculated using the U.S. Treasury yield curves in effect at the time of grant, for the periods within the expected life of the options. There were no option grants during 2009.

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 as of December 31, 2009:

	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, 2009	471,400	$ 46.01		
Exercised	(75,400)	42.52		
Forfeited, cancelled or expired	(46,600)	49.82		
Outstanding at December 31, 2009	349,400	46.25	6.3	$ 2,864
Exercisable at December 31, 2009	168,700	$ 42.95	4.8	$ 1,940

(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 of 2009 and the exercise price, multiplied by the number of exercisable, in-the-money options.

The total intrinsic value of options exercised during the years ended December 31, 2009, 2008 and 2007 was $0.5 million, $0.1 million and $0.7 million, respectively. At December 31, 2009, 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 0.8 years. At December 31, 2009, 333,000 LP Units were available for grant in connection with the Option Plan, although, as noted above, we do not expect to make any future grants pursuant to the Option Plan. The fair value of options vested was $0.4 million, $0.2 million and $0.2 million during the years ended December 31, 2009, 2008, and 2007, respectively.

BUCKEYE PARTNERS, L.P.
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The following table summarizes the total unit-based compensation expense included in our consolidated statements of operations for the periods indicated:

	Year Ended December 31,		
	2009	2008	2007
Operating expenses	$ 1,018	$ 374	$ 291
General and adminstrative expenses	1,827	112	87
Total unit-based compensation expense (1)	$ 2,845	$ 486	$ 378

(1) The increase from the year ended December 31, 2008 to the year ended December 31, 2009 is primarily due to grants under the 2009 LTIP and the Deferral Plan, both of which became effective in 2009.

19. EMPLOYEE STOCK OWNERSHIP PLAN

Services Company provides the ESOP to the majority of its employees hired before September 16, 2004. Employees hired by Services Company after September 15, 2004, and certain employees covered by a union multiemployer pension plan, do not participate in the ESOP. The ESOP owns all of the outstanding common stock of Services Company.

At December 31, 2009, the ESOP was directly obligated to a third-party lender for $7.7 million with respect to the 3.60% Notes due 2011 (the 3.60% ESOP Notes). The 3.60% ESOP Notes were issued on May 4, 2004 to refinance Services Company s 7.24% ESOP Notes which were originally issued to purchase Services Company common stock. The 3.60% ESOP Notes are collateralized by Services Company common stock and are guaranteed by Services Company. We have committed that, in the event that the value of our LP Units owned by Services Company falls to less than 125% of the balance payable under the 3.60% ESOP Notes, we will fund an escrow account with sufficient assets to bring the value of the total collateral (the value of LP Units owned by Services Company and the escrow account) up to the 125% minimum. Amounts deposited in the escrow account are returned to us when the value of the LP Units owned by Services Company returns to an amount which exceeds the 125% minimum. At December 31, 2009, the value of the LP Units owned by Services Company was approximately $89.3 million, which exceeded the 125% requirement.

Services Company stock is released to employee accounts in the proportion that current payments of principal and interest on the 3.60% ESOP Notes bear to the total of all principal and interest payments due under the 3.60% ESOP Notes. Individual employees are allocated shares based upon the ratio of their eligible compensation to total eligible compensation. Eligible compensation generally includes base salary, overtime payments and certain bonuses.

We contributed 2.6 million LP Units to Services Company in August 1997 in exchange for the elimination of our obligation to reimburse Buckeye GP and its parent for certain executive compensation costs, a reduction of the incentive compensation paid by us to Buckeye GP under the incentive compensation agreement, and other changes that made the ESOP a less expensive fringe benefit for us. Effective on January 1, 2009, we resumed paying for all executive compensation and benefits earned by Buckeye GP s four highest salaried officers in return for an annual fixed payment from BGH of $3.6 million. Funding for the 3.60% ESOP Notes is provided by distributions that Services Company receives on the LP Units that it owns and from cash payments from us, as required, to cover any shortfall between the distributions that Services Company receives on the LP Units that it owns and amounts currently due under the 3.60% ESOP Notes (the top-up). We will also incur ESOP-related costs for taxes associated with the sale and taxable income of our LP Units and for routine administrative costs. Total ESOP costs charged to earnings were $0.6 million during the year ended December 31, 2009. During the years ended December 31, 2008 and 2007, ESOP costs were reduced by $0.1 million and $0.5 million, respectively, as estimates of future shortfalls between the distributions that Services Company receives on the LP Units that it owns and amounts currently due under the 3.60% ESOP Notes were reduced to reflect higher distributions on the LP Units than were previously anticipated.

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20. 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 Holdings, LLC (BGH GP). Affiliates of each of ArcLight and Kelso & Company, 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 substantially all 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 $133.6 million, $101.2 million and $93.4 million for the years ended December 31, 2009, 2008 and 2007, respectively. We reimbursed Services Company for these costs.

Services Company, which is beneficially owned by the ESOP, owned 1.6 million of our LP Units (approximately 3.2% of our LP Units outstanding) as of December 31, 2009. 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 $7.2 million, $7.4 million and $7.2 million for the years ended December 31, 2009, 2008 and 2007, respectively. During the year ended December 31, 2009, ESOP related costs charged to earnings were $0.6 million. During the years ended December 31, 2008 and 2007, ESOP costs were reduced by $0.1 million and $0.5 million, respectively, as estimates of future shortfalls between the distributions that Services Company receives on the LP Units that it owns and amounts currently due under the ESOP Notes were reduced to reflect higher distributions on the LP Units than were previously anticipated.

We incurred a senior administrative charge for certain management services performed by affiliates of Buckeye GP of $0.5 million, $1.9 million and $1.9 million for the years ended December 31, 2009, 2008 and 2007, respectively. 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.

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 $45.7 million, $38.9 million and $30.0 million during the years ended December 31, 2009, 2008 and 2007, respectively.

As discussed in Note 4, on January 18, 2008, we acquired all the member interests of Lodi Gas. The Lodi Gas acquisition was a related party transaction because Lodi Gas was indirectly owned by affiliates of ArcLight. Due to ArcLight s indirect ownership interest in Buckeye GP, the Audit Committee of Buckeye GP, made up of independent directors and represented by independent legal counsel and financial advisors, reviewed and approved the terms of the Lodi Gas acquisition, including the purchase price, as fair and reasonable to us in accordance with our partnership agreement.

Two of Buckeye GP s current directors, Robb E. Turner and John F. Erhard, had an indirect ownership interest in affiliates of ArcLight, the sellers of Lodi Gas. As a result of their indirect ownership interests in those ArcLight affiliates, Messrs. Turner and Erhard received approximately $7.9 million and $16,700, respectively, from the sale of Lodi Gas to us in 2008.

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21. PARTNERS CAPITAL (DEFICIT) AND DISTRIBUTIONS

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

In accordance with our partnership agreement, capital accounts are maintained for our general partner and limited partners. Our partnership agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that our limited partners, general partner and incentive distribution rights holders will receive. Net income reflected under GAAP in our consolidated financial statements is first allocated to the incentive distribution rights holders and then between the general partner and the limited partners based on their proportionate interest in us. Our general partner s and limited partners capital accounts maintained pursuant to our partnership agreement are different from those maintained under U.S. federal tax law because of various book to tax adjustments.

General Partner s Interest

Our general partner s equity account generally consists of its cumulative share of our net income less cash distributions made to it in respect of its incentive distribution rights and general partner interest plus capital contributions that it has made to us (see our consolidated statements of partners capital (deficit) for a detail of the general partner s equity account). We make quarterly cash distributions of 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 that we make during a period may exceed our net income for the period. Cash distributions in excess of net income allocations and capital contributions during recent years have resulted in a declining balance in the general partner s equity account in previous years. As a result, future cash distributions that exceed net income allocations to, and capital contributions by, our general partner, if any, could result in a negative balance in the general partner s equity account.

Such a negative balance would not represent an asset of us, nor would it represent a liability of our general partner to us. According to our partnership agreement, in the event of our dissolution, after satisfying our liabilities, assets are divided among the partners in proportion to, and to the extent of, the positive balances in their capital accounts. If the general partner s equity account contained a negative balance after all allocations are made between the partners, the general partner would not be required to repay any such deficit.

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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 January 1, 2007	243,914	39,453,846	39,697,760
LP Units issued pursuant to the Option Plan		55,700	55,700
LP Units issued in underwritten public offering		6,208,600	6,208,600
Units outstanding at December 31, 2007	243,914	45,718,146	45,962,060
LP Units issued pursuant to the Option Plan		9,200	9,200
LP Units issued in underwritten public offering		2,645,000	2,645,000
Units outstanding at December 31, 2008	243,914	48,372,346	48,616,260
LP Units issued pursuant to the Option Plan		75,400	75,400
LP Units issued pursuant to the 2009 LTIP		519	519
LP Units issued in underwritten public offering		2,990,000	2,990,000
Units outstanding at December 31, 2009	243,914	51,438,265	51,682,179

Cash Distributions

We 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. All such distributions were paid on the then outstanding general partner units and LP Units. Cash distributions totaled \$230.4 million, \$203.2 million and \$164.3 million during the years ended December 31, 2009, 2008 and 2007, respectively.

Record Date	Payment Date	Amount Per LP Unit
February 6, 2007	February 28, 2007	$0.7875
May 7, 2007	May 31, 2007	0.8000
August 6, 2007	August 31, 2007	0.8125
November 5, 2007	November 30, 2007	0.8250
February 5, 2008	February 29, 2008	$0.8375
May 9, 2008	May 30, 2008	0.8500
August 8, 2008	August 29, 2008	0.8625
November 7, 2008	November 28, 2008	0.8750
February 12, 2009	February 27, 2009	$0.8875
May 11, 2009	May 29, 2009	0.9000
August 7, 2009	August 31, 2009	0.9125
November 7, 2009	November 28, 2009	0.9250

On February 5, 2010, we announced a quarterly distribution of \$0.9375 per LP Unit that was paid on February 26, 2010, to Unitholders of record on February 16, 2010. Total cash distributed to Unitholders on February 26, 2010 was approximately $60.8 million.

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22. 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 2009 LTIP awards calculated using the treasury stock method. Outstanding unit options and 2009 LTIP awards are excluded from the calculation of diluted earnings per LP Unit in periods we experience a net loss because the effect is antidilutive.

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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:

	Year Ended December 31,		
	2009	2008	2007
Net income allocation from continuing operations:			
Net income attributable to Buckeye Partners, L.P.	$ 140,982	$ 184,389	$ 155,356
Less: Income from discontinued operations		(1,230)	
Net income from continuing operations attributable to Buckeye Partners, L.P.	140,982	183,159	155,356
Less: General partner s allocation of incentive distributions from continuing operations	(54,745)	(32,920)	(27,058)
Net income from continuing operations available to limited partners and general partner after incentive distribution	86,237	150,239	128,298
General partner s ownership interest	0.480%	0.508%	0.576%
Income allocation from continuing operations to general partner based upon ownership interest	$ 414	$ 764	$ 738
General partner s incentive distribution from continuing operations	$ 54,745	$ 32,920	$ 27,058
Income allocation to general partner from continuing operations	414	764	738
Total income from continuing operations allocated to general partner	55,159	33,684	27,796
Adjustment for application of two-class method for MLPs (1)	(7,178)	7,316	4,997
Net income from continuing operations allocated to general partner in accordance with two-class method	$ 47,981	$ 41,000	$ 32,793
Net income allocation from discontinued operations:			
Income from discontinued operations	$	$ 1,230	$
Less: General partner s allocation of incentive distributions from discontinued operations		(366)	
Income from discontinued operations available to limited partners and general partner after incentive distribution		864	
General partner s ownership interest		0.508%	
Income from discontinued operations allocated to general partner in accordance with two-class method	$	$ 4	$
General partner s incentive distribution from discontinued operations	$	$ 366	$

Income from discontinued operations allocated to general partner				4		
Total income from discontinued operations allocated to general partner				370		
Adjustment for application of two-class method for MLPs (1)				81		
Income from discontinued operations allocated to general partner in accordance with two-class method	$		$	451	$	

(1) We allocate net income to our general partner based on the distribution 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.

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

	Year Ended December 31,		
	2009	2008	2007
Earnings per LP Unit Calculation:			
Numerator:			
Net income from continuing operations attributable to Buckeye Partners, L.P.	$ 140,982	$ 183,159	$ 155,356
Less: Net income allocated to general partner in accordance with two-class method	(47,981)	(41,000)	(32,793)
Net income from continuing operations available to limited partners in accordance with two-class method	$ 93,001	$ 142,159	$ 122,563
Income from discontinued operations	$	$ 1,230	$
Less: Net income from discontinued operations available to limited partners in accordance with two-class method		(451)	
Net income from discontinued operations available to limited partners in accordance with two-class method	$	$ 779	$
Denominator:			
Basic:			
Weighted average LP Units outstanding	50,620	47,747	42,051
Diluted:			
Weighted average LP Units outstanding	50,620	47,747	42,051
Dilutive effect of LP Unit options and LTIP awards granted	43	16	50
Total	50,663	47,763	42,101
Earnings per limited partner unit basic:			
Income from continuing operations	$ 1.84	$ 2.97	$ 2.91
Income from discontinued operations		0.03	
Earnings per limited partner unit basic	$ 1.84	$ 3.00	$ 2.91
Earnings per limited partner unit diluted:			
Income from continuing operations	$ 1.84	$ 2.97	$ 2.91
Income from discontinued operations		0.03	
Earnings per limited partner unit diluted	$ 1.84	$ 3.00	$ 2.91

23. BUSINESS SEGMENTS

We report and operate in five business segments: Pipeline Operations; Terminalling and Storage; Natural Gas Storage; Energy Services; and Development and Logistics. We previously referred to the Development and Logistics segment as the Other Operations segment. We renamed the segment to better describe the business activities conducted within the segment.

Pipeline Operations

The Pipeline Operations segment receives refined petroleum products from refineries, connecting pipelines, and bulk and marine terminals and transports those products to other locations for a fee. This segment owns and operates approximately 5,400 miles of pipeline systems in 15 states. This segment also has three refined petroleum products terminals with aggregate storage capacity of approximately 0.5 million barrels in three states.

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Terminalling and Storage

The Terminalling and Storage segment provides bulk storage and terminal throughput services. This segment has 59 refined petroleum products terminals in ten states with aggregate storage capacity of approximately 25.7 million barrels.

Natural Gas Storage

The Natural Gas Storage segment provides natural gas storage services at a natural gas storage facility in northern California that is owned and operated by Lodi Gas. The facility provides approximately 40 Bcf of total natural gas storage capacity (including pad gas) and is connected to Pacific Gas and Electric s intrastate gas pipelines that service natural gas demand in the San Francisco and Sacramento, California areas. The Natural Gas Storage segment does not trade or market natural gas.

Energy Services

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

Development and Logistics

The Development and Logistics segment consists primarily of our contract operation of approximately 2,400 miles of third-party pipeline and terminals, which are owned principally by major oil and gas, petrochemical and chemical companies and are located primarily in Texas and Louisiana. This segment also performs pipeline construction management services, typically for cost plus a fixed fee, for these same customers. The Development and Logistics segment also includes our ownership and operation of an ammonia pipeline and our majority ownership of the Sabina Pipeline in Texas.

Adjusted EBITDA

In the first quarter of 2009, we revised our internal management reports to provide senior management, including the Chief Executive Officer, more information about earnings before interest, taxes and depreciation and amortization (EBITDA) and Adjusted EBITDA. We define Adjusted EBITDA as EBITDA plus 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. In addition, our management has excluded the Buckeye NGL Pipeline impairment expense of $59.7 million and the reorganization expense of $32.1 million from Adjusted EBITDA in order to evaluate the results of our operations on a comparative basis over multiple periods. Adjusted EBITDA is now the primary measure used by senior management to evaluate our operating results and to allocate our resources. 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.

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

	Year Ended December 31,		
	2009	**2008**	**2007**
Revenue:			
Pipeline Operations	$ 392,667	$ 387,267	$ 379,345
Terminalling and Storage	136,576	119,155	103,782
Natural Gas Storage	99,163	61,791	
Energy Services	1,125,013	1,295,925	
Development and Logistics	34,136	43,498	36,220
Intersegment	(17,183)	(10,984)	
Total revenue	$ 1,770,372	$ 1,896,652	$ 519,347
Operating income:			
Pipeline Operations	$ 96,683	$ 153,250	$ 150,295
Terminalling and Storage	61,950	53,704	42,843
Natural Gas Storage	30,748	32,692	
Energy Services	13,521	6,039	
Development and Logistics	5,541	7,936	8,942
Total operating income	$ 208,443	$ 253,621	$ 202,080
Depreciation and amortization:			
Pipeline Operations	$ 38,434	$ 38,279	$ 37,411
Terminalling and Storage	7,851	6,583	5,610
Natural Gas Storage	6,458	5,003	
Energy Services	4,547	3,683	
Development and Logistics	1,874	1,751	1,630
Total depreciation and amortization	$ 59,164	$ 55,299	$ 44,651

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	Year Ended December 31,		
	2009	2008	2007
Adjusted EBITDA:			
Pipeline Operations	$ 230,172	$ 196,852	$ 192,236
Terminalling and Storage	72,518	60,410	49,363
Natural Gas Storage	42,214	42,374	
Energy Services	19,419	9,818	
Development and Logistics	6,607	8,785	9,549
Total Adjusted EBITDA	$ 370,930	$ 318,239	$ 251,148
GAAP Reconciliation:			
Net income	$ 146,900	$ 189,881	$ 160,617
Less: net income attributable to noncontrolling interests	(5,918)	(5,492)	(5,261)
Less: Income from discontinued operations		(1,230)	
Net income attributable to Buckeye Partners, L.P. unitholders from continuing operations	140,982	183,159	155,356
Interest and debt expense	74,851	74,387	50,378
Income tax expense (benefit)	(348)	796	763
Depreciation and amortization	59,164	55,299	44,651
EBITDA	274,649	313,641	251,148
Non-cash deferred lease expense	4,500	4,598	
Asset impairment expense	59,724		
Reorganization expense	32,057		
Adjusted EBITDA	$ 370,930	$ 318,239	$ 251,148

	Year Ended December 31,		
	2009	2008	2007
Capital additions: (1)			
Pipeline Operations	$ 34,209	$ 38,182	$ 47,563
Terminalling and Storage	20,927	30,245	18,341
Natural Gas Storage	20,860	49,514	
Energy Services	7,317	4,191	
Development and Logistics	700	297	1,963
Total capital additions	$ 84,013	$ 122,429	$ 67,867

Acquisitions and equity investments,

net of cash acquired:			
Pipeline Operations	$ 12,188	$ 19,169	$ 1,933
Terminalling and Storage	43,593	66,242	38,793
Natural Gas Storage		438,806	
Energy Services	2,532	143,306	
Development and Logistics			
Total acquisitions and equity investments, net	$ 58,313	$ 667,523	$ 40,726

(1) Amount includes ($3.3) million and $2.0 million of non-cash changes in accruals for capital expenditures for the years ended December 31, 2009 and 2008, respectively.

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	December 31, 2009	2008	2007
Total Assets:			
Pipeline Operations (1)	$1,592,916	$1,630,049	$1,673,744
Terminalling and Storage	532,971	473,807	385,446
Natural Gas Storage	573,261	503,278	
Energy Services	482,025	333,967	
Development and Logistics	74,476	93,309	74,462
Total assets	$3,255,649	$3,034,410	$2,133,652
Goodwill:			
Pipeline Operations	$	$	$
Terminalling and Storage (2)	38,184	39,952	11,355
Natural Gas Storage	169,560	169,560	
Energy Services	1,132	1,132	
Development and Logistics			
Total goodwill	$ 208,876	$ 210,644	$ 11,355

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

(2) Goodwill decreased by $1.8 million as of December 31, 2009 from December 31, 2008 due to the finalization of the purchase price allocation relating to the acquisition of a terminal in Albany, New York in 2008;

this $1.8 million was allocated to property, plant and equipment.

24. SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2009	**2008**	**2007**
Cash paid for interest (net of capitalized interest)	$65,805	$62,986	$49,652
Cash paid for income taxes	2,283	958	1,048
Capitalized interest	3,401	2,335	1,469
Non-cash changes in assets and liabilities:			
Change in capital expenditures in accounts payable	$ (3,296)	$ 1,957	$ 2,377
Hedge accounting	18,450	3,357	6,951
Environmental liability assumed in acquisition	1,480	5,644	

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

25. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data for the years ended December 31, 2009 and 2008 is set forth below. Quarterly results were influenced by seasonal and other factors inherent in our business.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2009					
Revenue	$416,840	$351,220	$423,444	$578,868	$1,770,372
Operating income (loss) (1)	70,103	(34,508)	75,965	96,883	208,443
Net income (loss) (1)	55,120	(47,271)	59,593	79,458	146,900
Net income (loss) attributable to Buckeye Partners, L.P. (1)	53,760	(48,371)	57,889	77,704	140,982
Earnings (losses) per LP Unit basic and diluted (2)	$ 0.87	$ (1.17)	$ 0.89	$ 1.17	$ 1.84
2008					
Revenue	$380,275	$492,548	$496,170	$527,659	$1,896,652
Operating income	58,132	58,668	64,451	72,370	253,621
Net income	44,269	42,232	47,858	55,522	189,881
Net income attributable to Buckeye Partners, L.P.	42,817	40,852	46,602	54,118	184,389
Earnings per LP Unit basic and diluted (2)	$ 0.72	$ 0.63	$ 0.75	$ 0.89	$ 3.00

(1) The second quarter of 2009 includes an impairment charge of $72.5 million related to assets held for sale and reorganization expenses of $28.1 million. The fourth quarter of 2009 includes a reversal of $12.8 million of the previously recognized impairment charge. See Notes 8 and 3, respectively.

(2) The sum of the per LP Unit amounts per

quarter does not equal the amount presented for the year ended December 31, 2009 due to changes in the average number of LP Units outstanding.

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Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

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

(a) Evaluation of Disclosure Controls and Procedures.

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

(b) Management s Report on Internal Control Over Financial Reporting.

Management s report on internal control over financial reporting is set forth in Item 8 of this Report and is incorporated by reference herein.

(c) Attestation Report of the Registered Public Accounting Firm.

The attestation report of our registered public accounting firm with respect to internal controls over financial reporting is set forth in Item 8 of this Report and is incorporated by reference herein.

(d) Change in Internal Control Over Financial Reporting.

During the fourth quarter of 2009, we implemented a new commodity trading and risk management supply system.

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

None.

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PART III

Item 10. *Directors, Executive Officers and Corporate Governance*

We do not have directors or officers. The executive officers and directors of Buckeye GP and Services Company perform all management functions for us and our Operating Subsidiaries. Directors of Buckeye GP are appointed by BGH, as the sole member of Buckeye GP. Officers of Buckeye GP are elected by the Board of Directors of Buckeye GP. See Certain Relationships and Related Transactions.

Directors of Buckeye GP

Set forth below is certain information concerning the directors of Buckeye GP.

Name	Age	Position with Our General Partner
Forrest E. Wylie	46	Chairman of the Board, CEO and Director*
Irvin K. Culpepper, Jr.	61	Director
John F. Erhard.	35	Director
Michael B. Goldberg	63	Director
C. Scott Hobbs	56	Director**
Mark C. McKinley	53	Director**
Oliver G. Rick Richard, III	57	Director**
Robb E. Turner	47	Director

* Also a director of Services Company.

** Director is an independent director of Buckeye GP and is not otherwise affiliated with Buckeye GP or its parent companies.

Mr. Wylie was named Chairman of the Board, CEO and a director of Buckeye GP on June 25, 2007. Mr. Wylie was also named Chairman of the Board, CEO and a director of the general partner of BGH on June 25, 2007. Mr. Wylie was also the President of Buckeye GP and the general partner of BGH from June 25, 2007 until he resigned, solely from such positions, on October 25, 2007. Prior to his appointment, he served as Vice Chairman of Pacific Energy Management LLC, an entity affiliated with Pacific Energy Partners, L.P., a refined product and crude oil pipeline and terminal partnership, from March 2005 until Pacific Energy Partners, L.P. merged with Plains All American, L.P. in November 2006. Mr. Wylie was President and CFO of NuCoastal Corporation, a midstream energy company, from May 2002 until February 2005. From November 2006 to June 25, 2007, Mr. Wylie was a private investor. Mr. Wylie currently serves on the board of directors and the Audit Committee of Eagle Bulk Shipping Inc. and Coastal Energy Company, both publicly traded entities. We believe the breadth of Mr. Wylie s experience in the energy industry, through his current position as our CEO and the past employment described above, as well as his current board of director positions, have given him valuable knowledge about our business and our industry that make him an asset to the Board of Directors of Buckeye GP. Furthermore, Mr. Wylie s leadership abilities and communication skills make him particularly qualified to be our Chairman.

Mr. Culpepper became a director of Buckeye GP on June 25, 2007. He has been an investor relations professional with Kelso & Company (Kelso) since 1988. Mr. Culpepper s many years in the field of investor relations have allowed him to bring an investor-focused perspective to the Board of Directors of Buckeye GP, which we believe enhances the functioning of our Board of Directors and its deliberations. These attributes uniquely qualify him to serve on the Board of Directors of Buckeye GP.

Mr. Erhard became a director of Buckeye GP on March 20, 2008. He has served ArcLight Capital Partners, LLC (ArcLight) since 2001, initially as an associate and currently as a principal. He also serves as a director of the general partner of BGH. Through his positions with ArcLight described above, Mr. Erhard has gained valuable experience in evaluating the financial performance and operations of companies in our industry, which we believe makes him a valuable member of the Board of Directors of Buckeye GP.

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Mr. Goldberg became a director of Buckeye GP on June 25, 2007. He has been a principal with Kelso since 1991. Mr. Goldberg is also a director of KAR Auction Services, Inc. and RHI Entertainment, LLC and was formerly a director of Eagle Bulk Shipping Inc. and Endo Pharmaceuticals, Inc. As a principal of Kelso, Mr. Goldberg has learned to critically evaluate the performance of companies. Furthermore, his many years as a corporate lawyer sharpened his skills for analysis and judgment. We believe these skills qualify Mr. Goldberg to serve as a member of the Board of Directors of Buckeye GP.

Mr. Hobbs became a director of Buckeye GP on October 1, 2007. From April 2006 to the present, he has been the owner of Energy Capital Advisors, LLC, a consulting firm in the energy industry. From January 2005 through March 2006, Mr. Hobbs was Executive Chairman of Optigas, Inc., a private midstream gas gathering and processing company, and, from January 2004 through February 2005, he was President and Chief Operating Officer of KFX, Inc. (now Evergreen Energy, Inc.), a public company that provides clean coal technologies. For almost 24 years, Mr. Hobbs worked for the Coastal Corporation with his last position there being Chief Operating Officer of Colorado Interstate Gas Co. and its Rocky Mountain affiliates. Mr. Hobbs is currently a director of American Oil and Gas Inc. where he serves on the Audit, Compensation and Governance committees. He is also a director of CVR Energy, Inc, where he serves on the Audit Committee. Mr. Hobbs has worked for many years with energy companies across a broad spectrum of sectors, including coal, natural gas gathering and processing and refined petroleum products transportation. This experience has given him a broader perspective on our operations, and, coupled with his extensive financial and accounting training and practice, has made him a valuable member of the Board of Directors of Buckeye GP.

Mr. McKinley became a director of Buckeye GP on October 1, 2007. He has served as Managing Partner of MK Resources, a private oil and gas development company specializing in the recovery and production of crude oil and the development of unconventional resource projects, for the past six years. Mr. McKinley is a director of Merrymac McKinley Foundation and is President and a director of Labrador Oil Company. The operational and business skills Mr. McKinley developed through his past experience in oil and gas development make him an important voice as an independent director on the Board of Directors of Buckeye GP.

Mr. Richard became a director of Buckeye GP on February 17, 2009. He is currently Chairman of Cleanfuel USA, an alternative vehicular fuel company, and for the past five years, he has been the owner and president of Empire of the Seed LLC, a private consulting firm in the energy and management industries, as well as the private investments industry. Mr. Richard served as Chairman, President and CEO of Columbia Energy Group (Columbia Energy) from April 1995 until Columbia Energy was acquired by NiSource Inc. in November 2000. Mr. Richard was appointed by President Reagan and confirmed by the United States Senate to the FERC, serving from 1982 to 1985. Mr. Richard also served as a director of the general partner of BGH from April 2008 until April 2009. Mr. Richard s breadth of experience in the energy sector, including being the chairman, president and CEO of a Fortune 500 company and commissioner of the FERC, have given him leadership and communication skills that make him exceptionally well-qualified to serve on the Board of Directors of Buckeye GP.

Mr. Turner became a director of Buckeye GP on June 25, 2007. He also serves as a director of the general partner of BGH. Mr. Turner co-founded ArcLight in 2001 and has been a principal since its inception. He has seventeen years of energy finance, corporate finance, and public and private equity investment experience. Mr. Turner s many years of experience relating to energy finance, corporate finance, and public and private equity investments have given him extensive financial and operational analysis capabilities. Additionally, Mr. Turner s leadership skills and business acumen are evidenced by his role as a co-founder of ArcLight. These qualities and skills make him a valuable member of the Board of Directors of Buckeye GP.

Executive Officers of Buckeye

Set forth below is certain information concerning our executive officers other than Mr. Wylie.

Name	Age	Position with Our General Partner
Robert A. Malecky	46	Vice President, Customer Services
Khalid A. Muslih	38	Vice President, Corporate Development
William H. Schmidt, Jr.	37	Vice President, General Counsel and Secretary
Clark C. Smith	55	President and Chief Operating Officer
Keith E. St.Clair	53	Senior Vice President and CFO

Mr. Malecky was named Vice President, Customer Services of Buckeye GP and the general partner of BGH in February 2010. Mr. Malecky has held the same position with Services Company since July 2009. From July 2000 to July 2009, Mr. Malecky served as Vice President, Marketing of Services Company.

Mr. Muslih was named Vice President, Corporate Development of Buckeye GP and the general partner of BGH in February 2010. Mr. Muslih has also been the President of the Buckeye Development and Logistics segment since May 2009. Mr. Muslih has held the Vice President, Corporate Development position with Services Company since June 2007. From November 2006 through June 2007, Mr. Muslih was a private investor. Mr. Muslih served as Vice President, Corporate Development of Pacific Energy Management LLC, an entity affiliated with Pacific Energy Partners, L.P., from March 2005 until Pacific Energy Partners, L.P. merged with Plains All American, L.P. in November 2006. Mr. Muslih served as Commercial Officer, Mergers & Acquisitions of NuCoastal Corporation from July 2002 until March 2005.

Mr. Schmidt became Vice President, General Counsel and Secretary of Buckeye GP on November 4, 2007 and President of Lodi Gas Storage, L.L.C. on August 3, 2009. He has served as the Vice President, General Counsel and Secretary of the general partner of BGH since November 4, 2007. Prior to that date, Mr. Schmidt had served as Vice President and General Counsel of Services Company since February 1, 2007 and as Associate General Counsel of Services Company since September 13, 2004. Mr. Schmidt practiced law at Chadbourne & Parke LLP, an international law firm, before joining Buckeye.

Mr. Smith became President and Chief Operating Officer of Buckeye GP on February 17, 2009 and has served the general partner of BGH in the same capacity since February 17, 2009. Mr. Smith served on the Board of Directors of Buckeye GP from October 1, 2007 until February 17, 2009. Mr. Smith was a private investor between July 2007 and October 2007. From June 2004 through June 2007, Mr. Smith served as Managing Director of Engage Investments, L.P., a private company established to provide consulting services to, and to make equity investments in, energy-related businesses. Mr. Smith was Executive Vice President of El Paso Corporation and President of El Paso Merchant Energy Group, a division of El Paso Corporation, from August 2000 until May 2003, and a private investor from May 2003 to June 2004.

Mr. St.Clair became Senior Vice President and CFO of Buckeye GP on November 10, 2008 and has served the general partner of BGH in the same capacity since November 10, 2008. Prior to his appointment, he served as Executive Vice President and CFO of Magnum Coal Company, one of the largest coal producers in Central Appalachia, from January 2006 until its sale to Patriot Coal Corporation (Patriot) in July 2008, after which he continued as an independent financial consultant to Patriot through October 2008. Mr. St.Clair was Senior Vice President and CFO of Trade-Ranger, Inc. (Trade-Ranger), a global business-to-business marketplace for electronic procurement and supply chain management for the oil and gas industry from March 2002 until its sale in May 2005, after which he continued as an independent financial consultant to Trade-Ranger until January 2006.

Section 16(a) Beneficial Ownership Reporting Compliance

Pursuant to Section 16(a) of the Exchange Act, our officers and directors, and persons beneficially owning more than 10% of our LP Units, are required to file with the SEC reports of their initial ownership and changes in ownership of LP Units. Our officers and directors, and persons beneficially owning more than 10% of our LP Units are also required by SEC regulations to furnish us with copies of all Section 16(a) forms they file. Based solely on

its review of Forms 3, 4 and 5 furnished to us and written representations from certain persons that no other reports were required for those persons, we believe that for 2009, all officers and directors, and persons beneficially owning more than 10% of our LP Units, who were required to file reports under Section 16(a) complied with such requirements.

Committees of the Board of Directors

Audit Committee

Buckeye GP has an Audit Committee (the Audit Committee) composed of C. Scott Hobbs (Chairman), Mark C. McKinley and Oliver G. Rick Richard, III. The members of the Audit Committee are independent, non-employee directors of Buckeye GP and are not officers, directors or otherwise affiliated with Buckeye GP or its parent companies. Buckeye GP s Board of Directors has determined that no Audit Committee member has a material relationship with Buckeye GP. The Board of Directors of Buckeye GP has also determined that Mr. Hobbs qualifies as an Audit Committee financial expert as defined in Item 407(d)(5) of Regulation S-K.

The Audit Committee provides independent oversight with respect to our internal controls, accounting policies, financial reporting, internal audit function and independent auditors. The Audit Committee also reviews the quality, independence and objectivity of the independent and internal auditors. The Audit Committee has sole authority as to the retention, evaluation, compensation and oversight of the work of the independent auditors. The independent auditors report directly to the Audit Committee. The Audit Committee also has sole authority to approve all audit and non-audit services provided by the independent auditors. The charter of the Audit Committee is available on our website at *www.buckeye.com* by browsing to the Corporate Governance subsection of the Investor Center menu.

The Audit Committee may act as a conflicts committee or a special committee at the request of Buckeye GP to determine matters that may present a conflict of interest between Buckeye GP or its parent companies and us.

The Audit Committee has established procedures for the receipt, retention and treatment of complaints received regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters. These procedures are part of the Business Code of Conduct and are available on our website at *www.buckeye.com* by browsing to the Corporate Governance subsection of the Investor Center menu.

Compensation Committee, Compensation Committee Interlocks and Insider Participation

As a limited partnership that is listed on the NYSE, we are not required to have a Compensation Committee. In order to conform to best governance practices, however, in 2007 the Board of Directors of Buckeye GP determined that a Compensation Committee was appropriate. The Compensation Committee currently is composed of Oliver G. Rick Richard, III (Chairman), Michael B. Goldberg, C. Scott Hobbs, Mark C. McKinley and Robb E. Turner. Messrs. Richard, Hobbs and McKinley are independent directors (as that term is defined in the applicable NYSE rules and Rule 10A-3 of the Exchange Act) and non-employee directors (as that term is defined in Rule 16b-3 of the Exchange Act). The non-independent directors are Messrs. Goldberg and Turner, who are affiliated with BGH GP, the sole member of Mainline Management, the general partner of BGH. In 2008, Mr. Clark C. Smith served on the Board of Directors and on the Compensation Committee of Buckeye GP.

The Compensation Committee oversees the determination and allocation of compensation among our senior management, including our named executive officers. Among other things, the Compensation Committee is responsible for:

- Establishing, implementing, and overseeing the administration of all of our compensation philosophies and policies;

- Approving actual salaries and incentive awards for our executive officers, including our named executive officers;

Reviewing and approving the annual compensation objectives for our executive officers;

Evaluating the performance of our executive officers, including our named executive officers, in pursuing the goals and objectives approved by the Compensation Committee, as well as the goals and objectives set forth in our annual budget;

Reviewing and approving with the CEO or President general compensation guidelines for our executive officers other than named executive officers, including proposed salary ranges and merit increase guidelines;

Overseeing any incentive compensation plans for our executive officers;

Performing the risk assessment analysis;

Annually reviewing total compensation for named executive officers, including salaries, annual and long-term incentives, severance plans, retirement and savings plans, and other benefits, comparing such plans and arrangements to those of our peer group and to the named executive officers in past years, ensuring appropriate levels of incentive to management and aligning management s objectives with the interests of Unitholders; and

Selecting and overseeing the performance of any outside consultants retained to review our compensation program and entering into retention agreements with any such consultants establishing their fees and any other retention terms.

The Compensation Committee meets several times throughout the year to act on the responsibilities above. The Compensation Committee may also act by written consent from time to time in response to events occurring between scheduled meetings. The Compensation Committee may seek guidance or input from the CEO when making determinations about the compensation of the executive officers other than the CEO. The CEO and the President also may provide recommendations to the Compensation Committee concerning the high-level allocation of incentive award pools among the senior management other than executive officers. The CEO and the President also may determine the salaries and amounts of individual incentive awards to senior management members other than executive officers. The charter of the Compensation Committee is available on our website at *www.buckeye.com* by browsing to the Corporate Governance subsection of the Investor Center menu.

The Compensation Committee has retained Mercer, LLC (Mercer) as its independent compensation consultant to evaluate the compensation of our executive officers, including our named executive officers, in comparison to the market and a peer group of other MLPs. See the discussion below under the heading Compensation Discussion and Analysis Administration of Executive Compensation Programs and Methodology for more information.

Finance Committee

Buckeye GP has a Finance Committee, which currently consists of two directors: Robb E. Turner (Chairman) and Michael B. Goldberg. The Finance Committee provides oversight and advice with respect to our capital structure.

Corporate Governance Matters

We have a Code of Ethics for Directors, Executive Officers and Senior Financial Employees that applies to, among others, the Chairman, CEO, President, CFO and Controller of Buckeye GP, as required by Section 406 of the Sarbanes Oxley Act of 2002. Furthermore, we have Corporate Governance Guidelines and a charter for our Audit Committee and Compensation Committee. Each of the foregoing is available on our website at *www.buckeye.com* by browsing to the Corporate Governance subsection of the Investor Center menu. We provide copies, free of charge, of any of the foregoing upon receipt of a written request. We disclose amendments to, or director and executive officer waivers from, the Code of Ethics, if any, on our website, or by Form 8-K to the extent required.

You can also find information about us at the offices of the NYSE, 20 Broad Street, New York, New York 10005 or at the NYSE s Internet site (*www.nyse.com*). The certifications of Buckeye GP s CEO and CFO required by Section 302 of the Sarbanes-Oxley Act have been included as exhibits to this Report.

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Communication with the Board of Directors

A holder of our LP Units or other interested party who wishes to communicate with the non-management directors of Buckeye GP may do so by contacting William H. Schmidt, Jr., Vice President, General Counsel and Secretary, at the address or phone number appearing on the front page of this Report. Communications will be relayed to the intended recipient of the Board of Directors of Buckeye GP except in instances where it is deemed unnecessary or inappropriate to do so pursuant to the procedures established by the Audit Committee. Any communications withheld under those guidelines will nonetheless be recorded and available for any director who wishes to review them.

NYSE Corporate Governance Listing Standards

The NYSE requires the chief executive officer of each listed company to certify annually that he is not aware of any violation by the company of the NYSE corporate governance listing standards as of the date of the certification, qualifying the certification to the extent necessary. The CEO of Buckeye GP provided such certification to the NYSE in 2009 without qualification.

Item 11. ***Executive Compensation***

Overview

We are managed by our general partner, Buckeye GP, which is 100% owned by BGH, a publicly traded MLP. BGH is owned approximately 62% by BGH GP and approximately 38% by the public. BGH GP is primarily owned by affiliates of ArcLight and Kelso. Members of our senior management also own a noncontrolling interest in BGH GP. BGH GP owns the general partner of BGH and, through such ownership, controls both BGH and us.

Services Company employs almost all of the employees who provide services to us and our Operating Subsidiaries, including Buckeye GP s officers. Pursuant to a Services Agreement, our Operating Subsidiaries reimburse Services Company for the cost of the employee services provided by Services Company.

Compensation Discussion and Analysis

Named Executive Officers

We do not have officers or directors. Our business is managed by the Board of Directors of our general partner, Buckeye GP, and the executive officers of Buckeye GP perform all of our management functions. Thus, the executive officers of Buckeye GP are our executive officers. In this Compensation Discussion and Analysis, we address the compensation determinations and the rationale for those determinations relating to our CEO, CFO and our next three most highly compensated executive officers. SEC rules also require us to discuss the compensation of any former executive officer whose 2009 compensation would have made him one of our other three most highly compensated executive officers if he had remained an executive officer on December 31, 2009. We refer to these executive officers collectively as our named executive officers . In 2009, our named executive officers were:

Forrest E. Wylie, Chairman and CEO;

Keith E. St.Clair, Senior Vice President and CFO;

Clark C. Smith, President and Chief Operating Officer;

Robert A. Malecky, Vice President, Customer Services;

Khalid A. Muslih, Vice President, Corporate Development; and

Stephen C. Muther, former President.

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Our Compensation Philosophy

We believe a significant portion of the compensation for each of our named executive officers should be incentive-based to emphasize a pay-for-performance philosophy. Our named executive compensation program is structured to attract, retain and motivate skilled and experienced executives who can grow our business while maintaining our high standards of customer service and safety. The most important performance metric for us is whether our executives can increase our distributable cash flow per unit. The best way to motivate our named executive officers to achieve this goal is to offer both short and long-term incentives, and the best way to align our executives interests with those of our Unitholders is to use both cash and equity awards to provide those incentives.

The compensation program that our Compensation Committee designed to incentivize our named executive officers to implement the principles above includes the following elements:

- annual base salary;
- non-equity annual incentive compensation pursuant to our AIC Plan;
- discretionary annual bonus awards; and
- long-term equity incentive awards, including:
  - phantom units issued pursuant to our 2009 LTIP; and
  - performance units issued pursuant to the 2009 LTIP.

We provide additional retirement and other medical benefits for our named executive officers similar to those provided by other companies in our industry of similar, size, maturity and market capitalization. See the discussion below following the Summary Compensation Table under the heading Retirement and Other Benefits for more information.

Administration of Executive Compensation Programs and Methodology

Our Compensation Committee administers the compensation program for our executive officers, including our named executive officers. The Compensation Committee retained Mercer as its independent compensation consultant in 2009. Mercer was engaged by the Compensation Committee to provide an assessment of the competitiveness of executive compensation for our named executive officers and to provide guidance on the calibration of equity awards to our named executive officers under the 2009 LTIP compared to prior grants under the Unit Option and Distrbution Equivalent Plan (Option Plan). Mercer reported to the Compensation Committee directly and provided the Compensation Committee with an independent assessment of the compensation of executives at our peer companies in order to assist the Compensation Committee in determining whether the overall compensation packages for each of our named executive officers are competitive. This assessment consisted of analyzing the following components of compensation:

- base salary;
- target annual incentive compensation as a percentage of base salary;
- target total cash compensation;
- long-term incentives; and
- total direct compensation.

For purposes of its analysis, Mercer utilized a peer group of nine other publicly traded MLPs. The companies in the peer group were: Energy Transfer Partners, L.P., Sunoco Logistics Partners L.P., Global Partners LP, Oneok Partners, L.P., Inergy, L.P., NuStar Energy, L.P., Magellan Midstream Partners, L.P., Genesis Energy, L.P. and Atlas Pipeline Holdings, L.P. While the peer group data provided by Mercer provides useful comparisons, the Compensation Committee takes into account other factors as it deems appropriate and uses the data as a guide rather than a rule when establishing the compensation packages for our named executive officers.

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Process and Timing of Compensation Decisions

The Compensation Committee reviews and approves all compensation for our executive officers, including our named executive officers. Early in each calendar year, our Board of Directors approves our financial objectives for the current year, and the Compensation Committee then factors them into its establishment of Partnership and any other objectives for each named executive officer under the AIC Plan. Generally, the Compensation Committee meets in the first quarter to determine the overall compensation package for each named executive officer for that year including: setting base salary, considering the grant of 2009 LTIP awards and establishing AIC Plan targets, in each case for the current year. Usually at the same meeting, the Compensation Committee reviews the degree to which we achieved the financial goals set by our Board of Directors, the degree to which each named executive officer achieved individual objectives, and the degree to which each named executive officer contributed to our objectives, in each case for the prior year. In light of the Compensation Committee s view that it is impossible to predict all factors that may require adjustments to compensation for a year in the first quarter of that year, the Compensation Committee also considers factors it deems appropriate for discretionary adjustments to compensation based on the events of the previous year. Based on these evaluations, the Compensation Committee approves AIC Plan payouts for the prior calendar year. As part of this process, our CEO provides a review of each other named executive officer s performance for the prior year and makes recommendations to the Compensation Committee to assist it in determining the various components of compensation. The CEO does not make recommendations with respect to his own compensation. While the Compensation Committee utilizes this information, and values the CEO s observations with regard to other named executive officers, the ultimate decisions regarding executive compensation are made by the Compensation Committee in accordance with its Charter.

The Compensation Committee may review executive compensation at such other times during the year as it deems appropriate, such as in connection with new appointments or promotions during the year.

Base Salaries

The base salaries for our named executive officers are reviewed annually by the Compensation Committee. For 2009, we generally sought to position base salaries for our named executive officers in the 50th percentile range of salaries for comparable executives included in the peer group data provided by our compensation consultant. By structuring base salaries in this range, we are able to emphasize our pay-for-performance philosophy and reward our named executive officers through annual incentive compensation. However, we may establish base salary at a rate outside this range due to differences in experience, as well as variations in responsibilities, performance and ability. In establishing the base salary of each named executive officer, the Compensation Committee also takes into consideration the other aspects of such person s compensation package, including both annual incentive awards and long-term equity incentive awards.

Based on the peer group data provided by our executive compensation consultant, the Compensation Committee determined that no material changes would be made to the base salaries of our named executive officers in 2009, with the exception of Mr. Muslih s base salary. Mr. Muslih s base salary was increased because his 2008 base salary fell below the competitive range of the 25th percentile based on the peer group data provided by our compensation consultant, and this increase moved his base salary closer to the 50th percentile. The base salaries of our named executive officers in 2009 were as follows:

Name	Base Salary in 2009	Percentage Increase
Forrest E. Wylie	$ 400,000	0%
Keith E. St.Clair	325,000	0%
Clark C. Smith	325,000	0%
Robert A. Malecky	243,706	0%
Khalid A. Muslih	225,000	8%
Stephen C. Muther	300,000	0%

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With the exception of Mr. Muslih, whose base salary falls slightly below a range competitive with the 50th percentile, all named executive officers base salaries are in a range competitive with the 50th percentile, or median, for comparable executive officers within our peer group.

Annual Incentive Compensation

Annual Incentive Compensation Plan

On March 13, 2009, the Compensation Committee approved the Buckeye Partners, L.P. Annual Incentive Compensation Plan, or AIC Plan. The AIC Plan is an annual incentive program that permits cash awards to certain employees, including our named executive officers, based on our overall financial performance and individual performance relative to pre-established target award levels.

The objectives of the AIC Plan are:

- to provide near-term incentives to achieve annual goals established for our employees that are considered important for organizational success; and

- to reward performance with pay that varies in relation to the extent to which the pre-established performance goals are achieved.

With the exception of Mr. Muther, who resigned as President effective February 17, 2009 in connection with his retirement in June 2009, all of our named executive officers participate in the AIC Plan and are eligible to receive incentive awards.

Under the AIC Plan for 2009, the Compensation Committee established a target award payout for each named executive officer. The target award levels for 2009 for Messrs. Smith and St.Clair were set forth in their employment offer letters dated February 11, 2009 and October 1, 2008, respectively, and such target award levels were based on their respective levels and positions. The target award levels for all other named executive officers were based on their responsibility level and position. The following table shows the 2009 AIC Plan target for each named executive officer, determined as a percentage of his base salary:

Name	Base Salary	Incentive Award Target as Percentage of Base Salary	Incentive Award Target
Forrest E. Wylie	$400,000	100%	$400,000
Keith E. St.Clair	325,000	100%	325,000
Clark C. Smith	325,000	100%	325,000
Robert A. Malecky	243,706	50%	121,853
Khalid A. Muslih	225,000	50%	112,500

The determination to pay the target award levels above to each named executive officer was based 75% on the achievement of pre-established financial performance goals and 25% on the achievement of pre-established individual performance goals. Each named executive officer s financial performance goals were tied to the financial performance of a business unit within Buckeye and/or the Partnership on a consolidated basis, in each case measured in terms of Adjusted EBITDA (See Item 7, Management s Discussion and Analysis of Financial Condition and Results of Operations for a discussion on how our management uses Adjusted EBITDA). The business units under the AIC Plan correspond to our reporting segments, namely Pipeline Operations, Terminalling and Storage, Natural Gas Storage, Energy Services and Development and Logistics (previously named Other Operations). Except for Mr. Malecky, all financial performance goals for our named executive officers were measured against our Adjusted EBITDA on a consolidated basis. Mr. Malecky s financial performance goals were allocated as follows: 25% based on our Adjusted EBITDA on a consolidated basis, 50% based on the Adjusted EBITDA of Pipeline Operations, 20% based on the Adjusted EBITDA of Terminalling and Storage and 5% based on the Adjusted EBITDA of Development and Logistics. For 2009, the Adjusted EBITDA targets were as follows:

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Business Unit	Adjusted EBITDA Target
Pipeline Operations	$212.6 million
Terminalling and Storage	$71.9 million
Natural Gas Storage	$53.2 million
Energy Services	$19.1 million
Development and Logistics	$5.3 million
Consolidated Partnership	**$362.1 million**

In evaluating the level of achievement of the financial performance goals, the Compensation Committee has the discretion to modify each named executive officers allocation based on the following additional qualitative factors:

- the actual aggregate maintenance capital expenditures relative to the achievement of our maintenance capital policy s objectives;
- the health, safety, and environmental record of the Partnership;
- the execution of the business plan and strategies of the Partnership; and
- the degree of teamwork exhibited across the workforce in the Partnership.

The individual performance goals for each of our named executive officers in 2009 are set forth below:

Forrest E. Wylie

- Work with each executive officer to achieve 2009 operating and financial goals;
- Implement and complete best practices initiative;
- Improve occupational health and safety performance of the Partnership;
- Facilitate targeted accretive acquisitions; and
- Finalize corporate succession planning policies and practices for key management.

Clark C. Smith

- Work with senior leadership team to achieve 2009 operating and financial goals;
- Promote leadership and integrity at Buckeye;
- Implement and complete best practices initiative;
- Improve occupational health and safety performance of the Partnership;
- Improve pipeline measurement performance;
- Develop new asset maintenance plan; and
- Finalize corporate succession planning policies and practices for key management.

Keith E. St.Clair

- Work with senior leadership team to achieve 2009 operating and financial goals;
- Implement and complete best practices initiative, including within the Partnership s finance function; and

Recruit key personnel in connection with restructuring of finance function.

Robert A. Malecky

Achieve pipeline and terminal revenue targets for 2009;

Facilitate growth capital projects that generate returns in excess of applicable hurdle rates;

Develop marketing talent and work on succession planning for marketing group; and

Support and implement best practices initiative.

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Khalid A. Muslih

Facilitate and manage targeted accretive acquisitions in 2009;

Rationalize NGL pipeline assets; and

Reevaluate Development and Logistic segment s business model.

The Compensation Committee did not place greater weight on any individual goal but assessed the individual performance of each named executive officer by considering the goals in the aggregate, retaining discretion to credit the full 25% award allocation based on the achievement of one or all individual performance goals.

For 2009, the Partnership exceeded its consolidated Adjusted EBITDA target, as did each business unit that was a factor in Mr. Malecky s AIC Plan award. As a result, all named executive officers received a 75% allocation of their target incentive award. The Compensation Committee also considered the individual performance of each named executive officer based on his individual performance goals and determined that each named executive officer met his individual performance goals in the aggregate. The Compensation Committee considered the following factors relating to the individual performance of all named executive officers:

the achievement of our 2009 operating and financial budget;

the successful implementation of the best practices initiative in the Partnership; and

the completion of accretive acquisitions in the challenging economic environment of 2009.

Based on the attainment of these financial and individual performance goals, annual incentive awards were paid under our AIC Plan to each of our named executive officers on February 18, 2010 in the amounts set forth below.

Name	Incentive Award Target	Actual Annual Incentive Award
Forrest E. Wylie	$400,000	$400,000
Keith E. St.Clair	325,000	325,000
Clark C. Smith	325,000	325,000
Robert A. Malecky	121,853	121,853
Khalid A. Muslih	112,500	112,500

Discretionary Bonuses

In addition to the pre-established awards described above, our AIC Plan permits, and the Compensation Committee retains discretion under the AIC Plan to pay, discretionary awards above each named executive officer s target award level. Our Compensation Committee believes this flexibility is a critical component of any short-term incentive program because it allows the Compensation Committee to recognize achievements in a changing environment. The Compensation Committee believes discretionary bonuses, properly used, will encourage our named executive officers to rise to the occasion, even in the most challenging of circumstances.

For 2009, discretionary bonuses were awarded to our named executive officers for two reasons:

Messrs. Malecky and Muslih played instrumental roles in 2009 business development transactions that are expected to significantly enhance our commercial operations and return to our Unitholders.

Messrs. Wylie, Smith and St.Clair provided critical leadership in the challenging implementation of our best practices initiative, which has helped to transform the Partnership into a more commercially focused organization.

The discretionary bonuses were determined by the Compensation Committee in its sole discretion, and were paid on February 18, 2010 in the amounts set forth below.

Name	Discretionary Bonus
Forrest E. Wylie	$ 100,000
Keith E. St.Clair	101,600
Clark C. Smith	175,200
Robert A. Malecky	243,706
Khalid A. Muslih	225,000

Long-Term Incentive Awards

2009 LTIP

We provide unit-based, long-term incentive compensation for certain employees, including our named executive officers, under our 2009 LTIP, which was approved by our Unitholders on March 20, 2009. Historically we provided long-term incentive compensation under the Option Plan. Following the adoption of the 2009 LTIP, new grants under the Option Plan ceased, and no grants to any employees, including named executive officers, were made pursuant to the Option Plan in 2009.

The 2009 LTIP provides for equity awards in the form of phantom units and performance units, either of which may be accompanied by DERs. DERs provide the participant with a right to receive a cash payment per phantom unit or performance unit equal to distributions per LP Unit paid by us. DERs are paid on phantom units at the time we pay such distribution on LP Units. DERs on performance units will not be paid until such performance units have vested. Our phantom units vest after three years of service from the date of grant and entitle a participant to receive an LP Unit, without payment of an exercise price, upon vesting. Performance units are notional LP Units whose vesting is subject to the attainment of one or more performance goals during a performance period, and which entitle a participant to receive LP Units, without payment of an exercise price, upon vesting. Performance units vest over a three-year performance period and are paid out based on a performance multiplier ranging between 0% and 200%, determined on the actual performance compared to a pre-established performance goal, which currently is distributable cash flow per LP Unit as set forth below:

Performance Measure	Performance Period	Threshold Performance Goal and Payout Multiplier	Stretch Performance Goal and Payout Multiplier
Distributable Cash Flow Per LP Unit	1/1/2009-12/31/2011	$ 4.39 50% Payout	$ 4.69 200% Payout

The distributable cash flow per LP Unit for the last year of the performance period (1/1/2011 12/13/2011) is used to measure whether the performance goal is achieved. The payout multiplier for performance below the threshold performance goal level is 0%. The payout multiplier for all other performance is determined on a linear scale, such that actual performance results falling between the threshold and stretch performance goals will result in payouts that are derived from ratable payout multipliers falling between the threshold payout multiplier (50%) and stretch payout multiplier (200%), with a target payout multiplier of 100%. For example, achievement of distributable cash flow per LP Unit exactly halfway between the threshold and stretch levels will result in a payout multiplier of 125%.

The fair values of both the performance unit and phantom unit grants are based on the average of the high and low sale prices of our LP Units on the date of grant adjusted for an estimated forfeiture rate as appropriate. Because we transitioned from an equity incentive plan based on unit options to restricted units, the Compensation Committee engaged Mercer to estimate the number of restricted units required to provide an equivalent value as compared to the February 2008 option grants in which we granted 138,500 unit options to approximately sixty-five (65) employees. Based on their analysis, which estimated the unit options granted on February 21, 2008 to have a value of $17.76 per unit option, Mercer recommended that we use the conversion rate of 2.25 unit options to one restricted unit for purposes of calibrating our March 2009 grants under the LTIP. In addition to the calibration analysis conducted by Mercer, the Compensation Committee considered:

peer group data;

each named executive officer s contribution to our long-term health and growth;

retention considerations based on the assessment of each named executive officer s contributions; and

any other considerations that the Compensation Committee deemed relevant with respect to a named executive officer, including the accomplishment of the individual s assigned objectives.

Based on these factors, the Compensation Committee approved the following grants of performance units and phantom units to our named executive officers on April 30, 2009:

	Performance Units			Phantom
Name	Threshold	Target	Maximum	Units
Forrest E. Wylie	4,767	9,534	19,068	4,767
Keith E. St.Clair	3,684	7,367	14,734	3,683
Clark C. Smith	3,900	7,800	15,600	3,900
Robert A. Malecky	1,300	2,600	5,200	1,300
Khalid A. Muslih	1,300	2,600	5,200	1,300

As a result of Mr. Muther s then-pending retirement, he did not receive a grant of performance units or phantom units under the LTIP. For a more detailed description of the 2009 LTIP, including the circumstances under which the vesting of phantom units and performance units may be accelerated, please see the narrative discussion below entitled Long-Term Incentive Plan following the Grant of Plan-Based Awards Table.

Override Units

BGH GP has granted certain limited liability company interests, called override units, to certain named executive officers. The Board of Directors of BGH GP determines the number of override units awarded to our named executive officers, if any, and the vesting schedules of those override units. Our Compensation Committee does not control this process, but may consider outstanding override unit awards when considering other long-term equity awards to our named executive officers. The BGH GP override units were not awarded by us and they do not constitute a cost to us, but there is a non-cash compensation expense charged to BGH. A description of the override units granted to our named executive officers and their vesting schedules is contained in the narrative discussion following the Summary Compensation Table below.

Non-Qualified Deferred Compensation

Deferral Plan

On December 16, 2009, the Compensation Committee approved the terms of the Buckeye Partners, L.P. Unit Deferral and Incentive Plan (the Deferral Plan). The Compensation Committee was expressly authorized to adopt the Plan pursuant to Section 7.1 of the 2009 LTIP which grants the Compensation Committee the authority to establish a program pursuant to which phantom units may be awarded in lieu of cash compensation at the election of the employee.

All of our named executive officers participate in the Deferral Plan. The Deferral Plan provides eligible employees, including our named executive officers, the opportunity to defer up to 50% of any cash award they would otherwise receive under the AIC Plan or other discretionary bonus program. Participants who elect to defer a portion of their cash awards are credited with deferral units equal in value to the amount of their cash award deferral. Under the Deferral Plan, participants are also credited with one matching unit for each deferral unit they receive. Both deferral units and matching units are phantom units governed by the 2009 LTIP, and are subject to service-based vesting restrictions. Participants are also entitled to DERs on each unit they receive pursuant to the Deferral Plan. Deferral units and matching units are settled in LP Units reserved under the 2009 LTIP.

In December 2009, each of our named executive officers elected to defer 50% of all cash awards to be received by them under the AIC Plan and pursuant to discretionary bonuses, except for Mr. St.Clair, who elected to defer

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25% of his cash awards. The value of the cash incentive awards and discretionary bonus awards that were deferred under the Deferral Plan are reported in our Summary Compensation Table below because they were earned by each named executive officer in 2009. The matching units that will be credited to our named executive officers in 2010 as a result of the deferral will not be reported in the 2009 Grant of Plan-Based Awards Table below because SEC guidance requires us to report equity grants in the year in which they are granted. As a result, such matching units will appear in the Grant of Plan-Based Awards table in our Annual Report on Form 10-K for the year ended December 31, 2010.

A more detailed description of the Deferral Plan, including a description of the acceleration of vesting of deferral and matching units, is contained in the narrative discussion entitled Deferral Unit and Incentive Plan following the Grant of Plan-Based Awards Table.

Benefit Equalization Plan

Except for Mr. Smith, all of our named executive officers received non-qualified deferred compensation in 2009 in the form of contributions by us to their Benefit Equalization Plan accounts. The Benefit Equalization Plan is a non-qualified deferred compensation plan. It provides that any employee whose company contributions to qualified pension and savings plans have been limited due to IRS limits on compensation allowable for calculating benefits under qualified plans will receive an equivalent benefit under the Benefit Equalization Plan for company-contributed amounts they would have received if there were no IRS limits. A more detailed description of the Benefit Equalization Plan is contained in the narrative discussion below following the Nonqualified Deferred Compensation Table.

Other Benefits

Named executive officers are generally eligible to participate in all of our employee benefit plans, such as medical, dental, vision, group life, short and long-term disability, and supplemental insurance, our ESOP and our retirement and savings plan, in each case on the same basis as other employees, subject to applicable laws. We also provide vacation and other paid holidays to all employees, including our named executive officers. In connection with their hiring, each of Mr. St. Clair and Mr. Smith received relocation benefits consistent with our relocation program for all officers. See the discussion below following the Summary Compensation Table under the heading Retirement and Other Benefits for more information.

Employment, Severance and Change in Control Arrangements

With the exception of Mr. Muther who retired in June 2009, none of our named executive officers have employment agreements. However, all of our named executive officers have severance and change in control arrangements that provide for severance payments upon termination of employment with or without a change of control. Messrs. St.Clair and Smith also receive severance if they resign for good reason, as defined under their respective agreements. Messrs. Wylie, Malecky and Muslih are each entitled to severance under the Severance Pay Plan for Employees of Buckeye Pipe Line Services Company. Messrs. St.Clair and Smith have individual severance agreements that were negotiated in connection with their hiring, and which were entered into on November 10, 2008 and February 17, 2009, respectively. The Compensation Committee approved these severance and change in control arrangements because the Compensation Committee believes that these benefits are appropriate for the caliber of executives hired and for the size of our company. In addition, the Compensation Committee desired to alleviate the financial hardships which may be experienced by the executives if their employment is terminated under specified circumstances and to reinforce and encourage the continued attention and dedication of those executives to their assigned duties, notwithstanding the potential impact a change in control transaction could have on their respective careers or positions. For more details regarding the terms of the severance and change in control arrangements see Payments upon Termination of Change in Control below.

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Compensation Committee Report

In light of the foregoing, as required by Item 407(e)(5) of Regulation S-K, our Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis with our management and, based on such review and discussions, has recommended to the Board of Directors of our general partner that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

THE COMPENSATION COMMITTEE
OF THE BOARD OF DIRECTORS OF
BUCKEYE GP LLC
Michael B. Goldberg
C. Scott Hobbs
Mark C. McKinley
Oliver G. Richard, III
Robb E. Turner

Summary Compensation Table

Name and Principal Position	**Fiscal Year**	**Salary ($)**	**Bonus ($)(1)**	**Unit Awards ($) (2)**	**Non-Equity Incentive Plan Compensation ($) (3)**	**All Other Compensation ($) (6)**	**Total ($)**
Forrest E. Wylie	2009	400,000	100,000	558,525	400,000	53,819	1,512,344
Chairman and Chief	2008	400,000				40,000	440,000
Executive Officer	2007	200,000		4,244,958		12,693	4,457,651
Keith E. St.Clair	2009	325,000	101,600	1,203,850	325,000	178,646	2,134,096
Senior Vice President and Chief Financial Officer	2008	37,500	72,000			1,875	111,375
Clark C. Smith (4) *President and Chief Operating Officer*	2009	280,000	175,200	1,229,235	325,000	73,857	2,083,292
Robert A. Malecky *Vice President, Customer Services*	2009	243,706	243,706	152,315	121,853	107,219	868,799
Khalid A. Muslih *Vice President, Corporate Development*	2009	223,261	225,000	152,315	112,500	41,758	754,834
Stephen C. Muther (5)	2009	182,308				2,020,010	2,202,318
Former President	2008	305,770				40,378	346,148
	2007	305,770		1,131,988		50,872	1,488,630

(1) Represents discretionary bonuses paid. Messrs. Malecky and Muslih deferred $60,927 and $56,250, respectively, of their discretionary bonuses pursuant to the Deferral Plan, and in February 2010 received phantom units, including both deferral units and matching units, issued under the 2009 LTIP as a result of the deferral. In accordance with SEC guidance, the values of the deferral units are disclosed on the 2009 Grants of Plan Based Awards Table in the Estimated Possible Payouts Under Non-Equity Incentive Plan Awards column. The matching units will appear in the Grants of Plan Based Awards Table that will be included in our Annual Report on Form 10-K for 2010.

(2) Amounts reflect the aggregate grant date fair

value (computed in accordance with FASB ASC Topic 718) of phantom unit awards and performance unit awards under the 2009 LTIP in 2009 as well as override units

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granted by BGH GP in 2007, 2008 and 2009. For a discussion of the valuations of the performance units and phantom units, please see the discussion in Note 18 in the Notes to Consolidated Financial Statements. See the narrative discussion below titled BGH GP Holdings, LLC Override Units for a discussion of the assumptions used in the valuation of the fair value of the override units. The table below details the unit awards set forth above:

Name	Year	Performance Unit Award Value ($)	Phantom Unit Award Value ($)	Override Operating Unit Value ($)	Override Value A Unit Value ($)	Override Value B Unit Value ($)	Total ($)
Forrest E. Wylie	2009	372,350	186,175				558,525
	2008						
	2007			2,179,843	1,319,379	745,736	4,244,958
Keith E. St.Clair	2009	287,718	143,840	354,808	247,516	169,968	1,203,850
	2008						
Clark C. Smith	2009	304,629	152,314	354,808	247,516	169,968	1,229,235

Robert A. Malecky	2009	101,543	50,772				152,315
Khalid A. Muslih	2009	101,543	50,772				152,315
Stephen C. Muther	2009						
	2008						
	2007			581,291	351,834	198,863	1,131,988

The vesting of the performance units are subject to the attainment of a pre-established distributable cash flow per LP Unit performance goal during the third year of a three fiscal year period. The grant date fair value of the performance awards reflected in the Summary Compensation Table is based on a target payout of such awards, using the average of the high and low trading prices for our LP Units on the date of grant ($39.055). If there is maximum payout under the performance unit awards, the grant date fair values of Messrs. Wylie, St.Clair, Smith, Malecky and Muslih s performance unit awards would be $744,701, $575,436, $609,258, $203,086 and $203,086, respectively.

(3) Represents annual incentive awards paid under the AIC Plan based on the achievement of pre-established financial performance goals and individual performance goals. Messrs. Wylie, St.Clair, Smith, Malecky and Muslih deferred $250,000, $106,650, $250,100, $121,853 and $112,500, respectively, of their AIC Plan awards pursuant to the Deferral Plan and received phantom units, including both deferral units and matching units, issued under the 2009 LTIP as a result of the deferral. In accordance with SEC

guidance, the values of the deferral units are disclosed on the 2009 Grants of Plan Based Awards Table in the Estimated Possible Payouts Under Non-Equity Incentive Plan Awards column. The matching units will appear in the Grants of Plan Based Awards Table that will be included in our Annual Report on Form 10-K for 2010.

(4) Mr. Smith became President and Chief Operating Officer of Buckeye GP on February 17, 2009.

(5) Effective February 17, 2009, Mr. Muther resigned from his position of President of Buckeye GP due to his pending retirement and retired as an employee of Services Company on June 30, 2009.

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(6) For each named executive officer, the amounts in the column labeled All Other Compensation consist of:

Name	Fiscal Year	Savings Plan Contributions ($) (a)	ESOP ($) (b)	Distribution Equivalents ($) (c)	Benefit Equalization Plan ($) (d)	Severance ($) (e)	Director Fees ($) (f)	Relocation ($) (g)	Total All Other Compensation ($)
Forrest E. Wylie	2009	24,500		13,050	16,269				53,819
	2008	23,000			17,000				40,000
	2007	12,693							12,693
Keith E. St.Clair	2009	24,500		10,082	15,825			128,239	178,646
	2008	1,875							1,875
Clark C. Smith	2009	22,188		10,676			8,750	32,243	73,857
Robert A. Malecky	2009	12,250	6,945	52,684	35,340				107,219
Khalid A. Muslih	2009	24,500		3,559	13,699				41,758
Stephen C. Muther	2009	9,115	6,290			2,004,605			2,020,010
	2008	11,500	23,628		5,250				40,378
	2007	11,250	26,497		13,125				50,872

(a) Amounts represent a 5% company contribution to the Retirement and Savings Plan for each of the named executive officers on wages of up to $245,000 for 2009, $230,000 for 2008 and $225,000 for 2007. Messrs. Wylie, St.Clair, Smith and Muslih also receive a dollar-for-dollar matching contribution on their contributions to the retirement and savings plan up to 5% of their pay.

(b) Amounts represent the value of Services Company stock allocated to each named executive officer who participated in the ESOP during 2009, in accordance with the terms of the ESOP described in the accompanying narrative.

(c) Amounts represent the distribution equivalents paid during 2009 on unvested phantom unit awards granted under the 2009 LTIP and held by the named executive officer. Pursuant to the 2009 LTIP, distribution equivalents for any period are determined by multiplying the number of outstanding unvested phantom units by the per LP Unit cash distribution paid by us on our LP Units for such period. For Mr. Malecky, amount also includes $49,125 in payment of distribution equivalents under the Option Plan. Pursuant to the Option Plan, distribution equivalents were calculated by multiplying (i) the number of our LP Units subject to such options that have not vested by (ii) 100% of our per LP Unit regular quarterly distribution.

(d) Amounts represent contributions to the named executive officer s account under the Benefit Equalization Plan. A description of the plan and the amounts of contributions credited to each named executive officer s account in 2009 are set forth in the 2009 Nonqualified Deferred Compensation Table and the accompanying narrative discussion below.

(e) Amount represents a $2,000,000 payment made to Mr. Muther by BGH and the costs in connection with continuing healthcare benefits under his amended and restated employment and severance agreement with BGH upon his June 30, 2009 retirement. See the discussion set forth in Payments Upon Termination and Change in Control below.

(f) Amount represents fees paid to Mr. Smith for his service as a director of Buckeye GP in 2009 prior to his resignation from the Board of Directors of

Buckeye GP on February 17, 2009.

(g) Amount represents incremental costs we incurred under our relocation program, which assists eligible employees who relocate at our request. Incremental costs are based upon charges we paid to a third-party relocation program administrator. Amounts include $17,572 and $1,386 paid to Messrs. St.Clair and Smith, respectively, during the year ended December 31, 2009 for the payment of taxes in connection with the relocation benefit.

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Employment Agreements

None of our named executive officers currently have employment agreements, but our named executive officers are entitled to certain payments upon termination of employment or change of control which are described in more detail below under the heading Payments Upon Termination or Change of Control. Mr. Muther, prior to his retirement, was a party to an amended and restated employment and severance agreement with BGH, which is described below under the heading Payments Upon Termination or Change of Control.

BGH GP Holdings, LLC Override Units

BGH GP granted limited liability company interests in BGH GP, called override units, to Messrs. St.Clair and Smith on July 27, 2009. On June 25, 2007, BGH GP granted override units to Messrs. Wylie, Malecky, Muslih and Muther. The override units are not awarded by our Compensation Committee, they are not paid by us, and they do not constitute an expense to us, but BGH incurs a non-cash expense charge. The limited liability company agreement of BGH GP has three types of override units: Value A Units, Value B Units and Operating Units. Information regarding the override units that BGH GP has granted to our named executive officers is set forth below:

Named Executive Officer	Grant Date	Value A # of Units	Value B # of Units	Operating # of Units	Total # of Units Awarded
Forrest E. Wylie	June 25, 2007	637,381	637,381	637,381	1,912,143
Keith E. St.Clair	July 27, 2009	106,230	106,230	106,230	318,690
Clark C. Smith	July 27, 2009	106,230	106,230	106,230	318,690
Robert A. Malecky	June 25, 2007	148,722	148,722	148,722	446,166
Khalid A. Muslih	June 25, 2007	148,722	148,722	148,722	446,166
Stephen C. Muther *	June 25, 2007	169,968	169,968	169,968	509,904

* Pursuant to the terms of the BGH GP limited liability company agreement governing the override units, Mr. Muther forfeited 50% of the override units he held as of June 30, 2009.

Grant Date Fair Value

Grant Date	Value A	Value B	Operating

June 25, 2007	$ 2.07	$ 1.17	$ 3.42
July 27, 2009	$ 2.33	$ 1.60	$ 3.34

Forfeiture

The override units are generally subject to forfeiture upon the occurrence of certain events before benchmark dates, which events and dates vary based on the type of override unit and the grantee. The override units owned by a named executive officer are subject to forfeiture if:

such named executive officer s employment is terminated for cause;

such named executive officer s employment is terminated due to death, disability or retirement (Value A Units and Value B Units only); or

such named executive officer s employment is terminated for any other reason prior to the occurrence of an exit event (as defined below) or the entry into a definitive agreement that would result in an exit event and an exit event does not occur within one year after the termination of employment.

For the purposes of this discussion, an exit event generally includes the sale by ArcLight, Kelso and their affiliates of their interests in BGH GP, the sale of substantially all the assets of BGH GP and its subsidiaries, or any other extraordinary transaction that the Board of Directors of BGH GP determines is an exit event.

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The table below sets forth the percentages of each named executive officer s override units that are subject to forfeiture upon the occurrence of certain events prior to the dates set forth in the table.

			Time Since Date of the Grant of Override Units							
Named Executive Officer	Unit Type	Reason for Forfeiture*	Before 1 Year	1 Year	18 Months	2 Years	30 Months	3 Years	42 Months	4+ Years
Forrest E. Wylie	A & B Units	Cause	100%	100%	100%	100%	100%	100%	100%	100%
		DDR	100%	75%	62.50%	50%	37.50%	25%	12.50%	0%
		Other	100%	100%	100%	100%	100%	100%	100%	100%
	Operating Units	Cause	100%	100%	100%	100%	100%	100%	100%	100%
		DDR	0%	0%	0%	0%	0%	0%	0%	0%
		Other	100%	75%	62.50%	50%	37.50%	25%	12.50%	0%
Keith E. St.Clair Clark C. Smith Robert A. Malecky Khalid A. Muslih	A & B Units	Cause	100%	100%	100%	100%	100%	100%	100%	100%
		DDR	100%	100%	100%	100%	100%	100%	100%	100%
		Other	100%	100%	100%	100%	100%	100%	100%	100%
	Operating Units	Cause	100%	100%	100%	100%	100%	100%	100%	100%
		DDR	0%	0%	0%	0%	0%	0%	0%	0%
		Other	100%	75%	62.50%	50%	37.50%	25%	12.50%	0%
Stephen C. Muther	A & B Units	Cause	100%	100%	100%	100%	100%	100%	100%	100%
		DDR	100%	100%	100%	100%	100%	100%	100%	100%
		Other	100%	100%	100%	50%	37.50%	25%	12.50%	0%
	Operating Units	Cause	100%	100%	100%	100%	100%	100%	100%	100%
		DDR	0%	0%	0%	0%	0%	0%	0%	0%
		Other	100%	75%	62.50%	50%	37.50%	25%	12.50%	0%

* Cause means termination of employment for cause. DDR means termination of employment due to death, disability or retirement. Upon Mr. Wylie s retirement (as opposed to the

termination of his employment upon death or disability), all of his Value A Units and Value B Units will be forfeited. Other means termination of employment for any other reason.

Distributions

The override units are entitled to share in distributions made by BGH GP under the circumstances set forth below.

Value A Units and Value B Units may only participate in distributions if the members of BGH GP that are affiliated with ArcLight and Kelso (collectively referred to as the ArcLight Kelso Members) receive an internal rate of return (compounded annually) of at least 10% and the ArcLight Kelso investment multiple is equal to or greater than 2.0. The ArcLight Kelso investment multiple is generally the sum of all the distributions the ArcLight Kelso Members have received from BGH GP prior to the time in question, divided by the total amount of capital contributions to BGH GP that the ArcLight Kelso Members have made prior to such time.

Additionally, all distributions on Value A Units and Value B Units are subject to the following performance criteria:

- if the ArcLight Kelso investment multiple is 2.0 or more, all Value A Units participate in distributions;

- if the ArcLight Kelso investment multiple is 3.5 or more, all Value B Units participate in distributions; and

- if the ArcLight Kelso investment multiple is greater than 2.0 but less than 3.5, a percentage of the Value B Units will participate in distributions based generally on a sliding scale with 0% participating at the 2.0 level and 100% participating at the 3.5 level.

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In addition to the forfeiture provisions described under the heading Forfeiture above, upon the occurrence of an exit event, any Value A Units and Value B Units that have not become eligible to participate in distributions in accordance with the criteria described above, and do not become eligible to participate in such distributions in connection with such exit event, will be forfeited without payment.

Distributions on the override units may be made as a result of an exit event or, from time to time prior to an exit event, when and as declared by the Board of Directors of BGH GP (we refer to distributions declared prior to an exit event as interim distributions). Distributions are generally made pro rata to each member of the LLC based on the number of LLC units held by such member, except that the amounts of any distribution in respect of each override unit shall be reduced and distributed to the other members of BGH GP until the cumulative amount withheld and redistributed for such override unit equals a benchmark amount. The benchmark amount of all override units held by our named executive officers is $10.00, but is subject to adjustment under certain circumstances. Additionally, the Board of BGH GP may determine a different benchmark amount for any new override units that it issues.

Holders of Value A Units or Value B Units that become eligible to participate in distributions upon satisfaction of the performance criteria summarized above are entitled to cumulative priority catch up distributions in respect of earlier interim distributions not made on those Value A Units and Value B Units upon a subsequent interim distribution or a distribution in connection with an exit event.

Operating Units that are still subject to forfeiture at the time of a distribution do not participate in interim distributions but are entitled to distributions in connection with an exit event. Additionally, Operating Units that are no longer subject to forfeiture are entitled to cumulative priority catch up distributions in respect of earlier interim distributions not made on such Operating Units upon a subsequent interim distribution or distribution in connection with an exit event. Finally, distributions on Operating Units that are not subject to forfeiture are not subject to the investment multiple performance criteria that are applicable to Value A Units and Value B Units.

Determination of Fair Value

We valued the override units using the Monte Carlo simulation method that incorporates the market-based vesting condition into the grant date fair value of the unit awards as required by FASB ASC Topic 718. The Monte Carlo simulation is a procedure to estimate future equity value from the time of the valuation date of June 25, 2007 or July 27, 2009, as applicable, to the exit event using the following assumptions:

- Current Equity Value of $10.00 per unit or total equity of $439.00 million at June 25, 2007 and $439.06 million July 27, 2009, based on the initial capital contributions made by the equity investors into BGH;

- Expected Life of 5.5 years for the 2007 valuation and 3.4 years for the 2009 valuation based on the historical average holding period for similar investments;

- Risk Free Rate of 4.92% for the June 25, 2007 valuation and 1.84% for the July 27, 2009 valuation based on the U.S. Constant maturity treasury rate for a term corresponding to the expected life of the override units;

- Volatility of 26% for the June 25, 2007 valuation and 45% for the July 27, 2009 valuation. Since BGH GP s primary assets are its ownership interest in BGH, volatility was estimated by using the volatility of BGH, along with comparisons to the volatility of other firms in the same industry as BGH over a period equal to the Expected Life of the override units; and

- Because the likelihood of an interim distribution is not probable due to the rigorous performance criteria, dividends of zero were assumed.

Requirements With Respect to Non-Competition and Non-Solicitation

The limited liability company agreement of BGH GP provides that, for a certain period of time, holders of the override units, which includes our named executive officers (referred to as the Management Members), may not become associated with or employed by any entity that is actively engaged in any geographic area in which BGH, Buckeye GP, we or any of our subsidiaries (collectively, the Buckeye Entities) does business in any business which is either in competition with the business of the Buckeye Entities conducted at any time during the 12 months

preceding the date such Management Member ceases to hold any equity interest in BGH GP or proposed to be conducted by the Buckeye Entities in the Buckeye Entities business plan as in effect as of the date such Management Member ceases to hold any equity interest in BGH GP.

The limited liability company agreement further provides that no Management Member shall directly or indirectly induce any employee of the Buckeye Entities to terminate employment with the Buckeye Entities or otherwise interfere with the employment relationship of the Buckeye Entities with any person who is or was employed by the Buckeye Entities. In addition, the limited liability company agreement prohibits any Management Member from soliciting or otherwise attempting to establish for himself any business relationship with any person who is, or at any time during the 12-month period preceding the date such Management Member ceases to hold any equity interest in BGH GP was, a customer, client or distributor of the Buckeye Entities.

Retirement and Other Benefits

The majority of our regular full-time employees hired before September 16, 2004 (including Messrs. Malecky and Muther) participate in Services Company s ESOP, which is a qualified plan. Services Company owns approximately 1.6 million of our LP Units. The ESOP owns all of the outstanding common stock of Services Company, or approximately 1.6 million shares. Accordingly, one share of Services Company common stock is generally considered to have a value equal to one of our LP Units. Under the ESOP, Services Company common stock is allocated to employee accounts quarterly. Individual employees are allocated shares based on the ratio of their eligible compensation to the aggregate eligible compensation of all ESOP participants. Eligible compensation generally includes base salary, overtime payments and certain bonuses. Upon termination of the employee s employment, the value of shares accumulated by an employee in the ESOP is payable to the employee or transferable to other qualified plans in accordance with the terms of the ESOP plan.

Services Company also sponsors a Retirement and Savings Plan (Retirement and Savings Plan) through which it provides retirement benefits for substantially all of its regular full-time employees (including our named executive officers), except those covered by certain labor contracts. The Retirement and Savings Plan consists of two components. Under the first component, Services Company contributes 5% of each eligible employee s covered salary to an employee s separate account maintained in the Retirement and Savings Plan. Under the second component, for all employees not participating in the ESOP, Services Company makes a matching contribution into the employee s separate account for 100% of an employee s contribution to the Retirement and Savings Plan up to 6% of an employee s eligible covered salary. For Services Company employees who participate in the ESOP, Services Company does not make a matching contribution. Each of our named executive officers receives the contribution equal to 5% of his salary (subject to certain IRS limits) annually, and these amounts vest ratably over a five year period. Because Messrs. Muther and Malecky participate in the ESOP, we do not make any matching contributions to the Retirement and Savings Plan on their behalf. Because Messrs. Wylie, St.Clair, Smith and Muslih do not participate in the ESOP, we do make matching contributions on their behalf.

Services Company also sponsors a Benefit Equalization Plan, which is described in detail in the narrative discussion following the Nonqualified Deferred Compensation Table below.

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2009 Grants of Plan-Based Awards Table

Name	Grant Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1) Target ($)	Estimated Future Payouts Under Equity Incentive Plan Award (2) Threshold (#)	Target (#)	Maximum (#)	All Other Unit Awards: Number of Units (#)	Grant Date Fair Value of Unit and Option Awards ($)
Forrest E. Wylie		400,000					
	April 30, 2009		4,767	9,534	19,068		372,350(5)
	April 30, 2009					4,767(3)	186,175
Keith E. St.Clair		325,000					
	April 30, 2009		3,684	7,367	14,734		287,718(5)
	April 30, 2009					3,683(3)	143,840
	July 27, 2009					318,690(4)	772,292
Clark C. Smith		325,000					
	April 30, 2009		3,900	7,800	15,600		304,629(5)
	April 30, 2009					3,900(3)	152,314
	July 27, 2009					318,690(4)	772,292
Robert A. Malecky		121,853					
	April 30, 2009		1,300	2,600	5,200		101,543(5)
	April 30, 2009					1,300(3)	50,772
Khalid A. Muslih		112,500					
			1,300	2,600	5,200		101,543(5)

April 30, 2009			
April 30, 2009		1,300(3)	50,772

(1) Represents annual incentive awards granted pursuant to the AIC Plan, with payment contingent on the achievement of pre-established financial performance goals and individual performance goals. The 2009 awards provided for a single payout. Messrs. Wylie, St.Clair, Smith, Malecky and Muslih deferred $250,000, $106,650, $250,100, $121,853 and $112,500, respectively, of their AIC Plan awards pursuant to the Deferral Plan and received phantom units, including both deferral units and matching units, issued under the 2009 LTIP as a result of the deferral. In accordance with SEC

guidance, the values of the deferral units are included in this column. The matching units will appear on the 2009 Grants of Plan Based Awards Table that will be included in our Annual Report on Form 10-K for 2010.

(2) Represents grants of performance units under the 2009 LTIP. See Long-Term Incentive Plan below. The vesting of the performance units are subject to the attainment of a pre-established distributable cash flow per LP Unit performance goal during the third year of a three fiscal year period. The grant date fair value of the performance units awards reflected in the table is based on a target payout of such awards.

(3) Represents grants of phantom units under the 2009

LTIP. See Long-Term Incentive Plan below.

(4) Represents override units granted by BGH GP. See BGH GP Holdings, LLC Override Units above.

(5) The grant date fair value of these awards is based on a target payout of such awards (computed in accordance with FASB ASC Topic 718), using the average of the high and low trading prices for our LP Units on the date of grant ($39.055). If there is maximum payout under the performance unit awards, the grant date fair values of Messrs. Wylie, St.Clair, Smith, Malecky and Muslih s performance unit awards would be $744,701, $575,436, $609,258, $203,086 and $203,086, respectively.

Long-Term Incentive Plan

The 2009 LTIP, which is administered by the Compensation Committee, provides for the grant of phantom units, performance units and in certain cases, DERs which provide the participant a right to receive payments based on distributions we make on our LP Units. Phantom units are notional LP Units whose vesting is subject to service-based restrictions or other conditions, and performance units are notional LP Units whose vesting is subject to the attainment of one or more performance goals. DERs are rights to receive a cash payment per phantom unit or performance unit, as applicable, equal to the per unit cash distribution we pay on our LP Units. DERs are paid on phantom units at the time we pay such distribution on LP Units. DERs on performance units will not be paid until such performance units have vested.

In the event we experience a change of control while a participant is employed by, or providing services to us, Buckeye GP, or any affiliate and (i) the participant is terminated without cause during the eighteen-calendar-month period following a change of control or (ii) the participant resigns for good reason during or shortly after such period, a participant s phantom units (and any unpaid DERs) will immediately vest and be paid within the 30-day period following the termination of employment and performance units (and any associated DERs) will vest and be paid based on a payout performance multiplier of 100% within the 30-day period following the termination of employment. For purposes of the 2009 LTIP, a change of control generally means:

- the sale or disposal by the Partnership of all or substantially all of its assets; or
- the merger or consolidation of the Partnership with or into another partnership, corporation or other entity, other than a merger or consolidation in which the Unitholders immediately prior to such transaction retain at least a 50% equity interest in the surviving entity; or
- the occurrence of one or more of the following events:
  - Buckeye GP ceases to be the sole general partner of the Partnership;
  - BGH ceases to own and control, directly or indirectly, 100% of the outstanding equity interests of Buckeye GP;
  - MainLine Management ceases to be the sole general partner of BGH; or
  - BGH GP ceases to own and control, directly or indirectly, 100% of the outstanding equity interests of MainLine Management;

    provided, *however*, that none of the four events described above will constitute a change of control if, following such event, either ArcLight or Kelso possess, or both ArcLight and Kelso collectively possess, directly or indirectly, the power to direct or cause the direction of the management and policies of the Partnership, whether through the ownership of voting securities, by contract, or otherwise; or
- the failure of ArcLight and Kelso collectively to possess, directly or indirectly, the power to direct or cause the direction of the management and policies of the Partnership, whether through the ownership of voting securities, by contract, or otherwise.

Cause generally means a finding by the Compensation Committee that the participant:

- has materially breached his or her employment, severance or service contract with the us;
- has engaged in disloyalty to us, including, without limitation, fraud, embezzlement, theft, commission of a felony or proven dishonesty;
- has disclosed trade secrets or our confidential information to persons not entitled to receive such information; or
- has breached any written non-competition, non-solicitation, invention assignment or confidentiality agreement between us and the participant.

Good Reason generally means the occurrence, without the participant s express written consent, of any of the following events during the eighteen-calendar-month period following a change of control, or the change of control period:

- a substantial adverse change in the participant s duties or responsibilities from those in effect on the date immediately preceding the first day of the change of control period;

a material reduction in the participant s annual rate of base salary or annual bonus opportunity as in effect immediately prior to commencement of a change of control period; or

requiring the participant to be based at a location more than 100 miles from the participant s primary work location as it existed on the date immediately preceding the first day of the change of control period, except for required travel substantially consistent with the participant s present business obligations.

The number of LP Units that may be granted under the 2009 LTIP may not exceed 1,500,000, subject to certain adjustments. The number of LP Units that may be granted to any one individual in a calendar year may not exceed 100,000. If awards are forfeited, terminated or otherwise not paid in full, the LP Units underlying such awards will again be available for purposes of the 2009 LTIP. Persons eligible to receive grants under the 2009 LTIP are (i) officers and employees of us, Buckeye GP and any of our affiliates and (ii) independent members of the Board of Directors of Buckeye GP or of MainLine Management. Phantom units or performance units may be granted to participants at any time as determined by the Compensation Committee.

The fair values of both the performance unit and phantom unit grants are based on the average market price of our LP Units on the date of grant computed in accordance with FASB ASC Topic 718. Compensation expense equal to the fair value of those performance unit and phantom unit awards that actually vest is estimated and recorded over the period the grants are earned, which is the vesting period. Compensation expense estimates are updated periodically. The vesting of the performance unit awards is also contingent upon the attainment of predetermined performance goals, which, depending on the level of attainment, could increase or decrease the value of the awards at settlement. Quarterly distributions paid on DERs associated with phantom units are recorded as a reduction of our Limited Partners Capital on our consolidated balance sheets.

Unit Deferral and Incentive Plan

The Deferral Plan provides eligible employees the opportunity to defer up to 50% of any cash award they would otherwise receive under the AIC Plan or other discretionary bonus program. Participants who elect to defer a portion of their bonus are credited with deferral units equal in value to the amount of their cash award deferral. Participants are also credited with a matching unit for each deferral unit they are granted. Both deferral units and matching units are phantom units based on LP Units and subject to service-based vesting restrictions. Participants are entitled to DERs on each unit they receive pursuant to the Deferral Plan, which provide named executive officers with the right to receive payments based on distributions we make on LP Units. Deferral units and matching units are settled in LP Units reserved under the 2009 LTIP.

Persons eligible to participate in the Deferral Plan are regular full-time salaried employees who have a base salary equal to or in excess of $150,000 (or such other amount as determined by the Compensation Committee) and who have been selected by the Compensation Committee to participate in the Deferral Plan. The number of deferral units and matching units that may be granted under the Deferral Plan is limited by the number of LP Units that may be granted under the 2009 LTIP, subject to certain adjustments.

Deferral elections under the Deferral Plan must be made no later than December 31 of the plan year prior to the date the applicable bonus would otherwise be paid. Once a deferral election is made for a plan year, it becomes irrevocable and cannot be cancelled or changed for that plan year. A participant becomes 100% vested in deferral units and matching units credited to his or her unit account during a plan year on the first day of the plan year that is three years after the plan year that the deferral units and matching units are credited to his or her unit account, provided that the participant is continuously employed by, or continuously provides services to us through that date. For example, deferral units and matching units that are credited to a participant s unit account in 2010 will vest on January 1, 2013. If a participant s employment is terminated by us without cause, unvested deferral units will immediately vest in full and unvested matching units will vest on a prorated basis, based on the portion of the vesting period during which the participant was employed by us. For purposes of determining the number of matching units that become vested on a prorated basis, the vesting period commences on the January 1 of the plan year in which we would otherwise have paid the annual cash award to the participant but for the participant s deferral election and ends three years later.

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In the event a change of control occurs while the participant is employed by, or providing services to us, Buckeye GP or any affiliate, and, during the eighteen-calendar-month period following a change of control, (i) the participant is terminated without cause, or (ii) the participant resigns for good reason, the participant s unvested deferral units and matching units will immediately vest in full. For purposes of the Deferral Plan, change of control, cause and good reason have the same meanings as set forth in the 2009 LTIP description above.

Option Plan

Our Option Plan historically provided for the grant of options to acquire our LP Units to certain of our and our affiliates officers and key employees. Recent changes in tax laws, including the regulations adopted under Internal Revenue Code Section 409A, have limited the effectiveness of the Option Plan and, as a result, we do not intend to make further grants under the Option Plan although existing grants under the plan will be unaffected and will remain subject to the terms of the plan. The Option Plan has historically been administered by the Board of Directors of Buckeye GP, but may be administered by our Compensation Committee in the future.

Options will generally vest three years after the date of grant, provided the optionee remains an employee of us or our affiliates at such time. Once an option becomes vested, the option remains exercisable for a period of seven years from the date of vesting, or for a shorter period specified by the Board of Directors or Compensation Committee.

The Option Plan also permitted the Board of Directors or Compensation Committee to grant distribution equivalent rights in tandem with option grants. Distribution equivalent rights provide the optionee with an accrual of an amount, subject to certain distribution targets set at the discretion of the Board of Directors or Compensation Committee, equal to the regular quarterly distribution on the number of unvested units subject to the option. Distribution equivalents are maintained in distribution equivalent accounts on our books and records and are paid to the optionee when units subject to the option vest. Distribution equivalents cease to accrue when units subject to an option vest. No interest accrues or is payable to the balance in any distribution equivalent account. No awards were granted under the Option Plan in 2009.

2009 Outstanding Equity Awards at Fiscal Year-End Table

		Option Awards				Unit Awards	
Name	Grant Date	Number of Securities Underlying Unexercised Options Exercisable (#) (1)	Number of Securities Underlying Unexercised Options Unexercisable (#)	Option Exercise Price	Option Expiration Date	Number of Units That Have Not Vested (#)	Market Value of Units That Have Not Vested ($) (2)
Forrest E. Wylie						4,767(3)	260,088
						9,534(4)	520,175
						1,912,143(5)	4,149,350(6)
Keith E. St.Clair						3,683(3)	200,944
						7,367(4)	401,944
						318,690(5)	691,558(6)
Clark C. Smith						3,900(3)	212,784
						7,800(4)	425,568
						318,690(5)	691,558(6)
Robert A. Malecky	2/26/2004	3,700		$42.10	2/26/2014	1,300(3)	70,928
	5/03/2004	5,000		$39.05	5/03/2014	2,600(4)	141,856
	4/01/2005	3,700		$45.88	4/01/2015	446,166(5)	968,180(6)
	2/23/2006	5,000		$44.73	2/23/2016		
	2/21/2007		7,000	$50.36	2/21/2017		
	11/24/2008		5,000	$31.24	12/31/2011		
Khalid A. Muslih	2/21/2008		5,000	$49.47	12/31/2011	1,300(3)	70,928
						2,600(4)	141,856
						446,166(5)	968,180(6)

(1) These amounts relate to options to purchase our LP Units under the Option Plan. All options vest after the expiration of three years from the grant date of the option and are exercisable for up to seven years after the vesting date,

except for those granted February 21, 2008 and November 24, 2008, which expire on December 31, 2011. See Note 18 in the Notes to Consolidated Financial Statements for further discussion of the assumptions related to unit option expense.

(2) For phantom units and performance units, the market value is calculated using a per LP Unit price of $54.56, the average of the high and low trading prices for our LP Units on December 31, 2009.

(3) Represents grants of phantom units under the 2009 LTIP. See Long-Term Incentive Plan above.

(4) Represents grants of performance units under the 2009 LTIP. See Long-Term Incentive Plan above. The

vesting of the performance units is subject to the attainment of a pre-established distributable cash flow per unit performance goal during the third year of a three fiscal year period. The number of performance units reflected in the table is based on a target payout of such awards.

(5) Represents compensation that is neither awarded by us nor paid by us. These amounts are unvested override units granted by BGH GP, which units consist of Operating Units, Value A Units and Value B Units. At December 31, 2009, Messrs. Wylie, St.Clair, Smith, Malecky and Muslih had 637,381, 106,230, 106,230, 148,722 and 148,722 unvested Operating Units, respectively. At

December 31, 2009, Messrs. Wylie, St.Clair, Smith, Malecky and Muslih had 637,381, 106,230, 106,230, 148,722, and 148,722 unvested Value A Units, respectively, and 637,381, 106,230, 106,230, 148,722, and 148,722 unvested Value B Units, respectively. The vesting of the override units is discussed above in the narrative section titled BGH GP Holdings, LLC Override Units .

(6) On December 31, 2009, the fair value of the Operating Units was $3.12 per unvested unit. On December 31, 2009, the fair value of the Value A and B Units was $2.06 and $1.33 per unit, respectively. The fair values of the override units were calculated using a Monte

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Carlo simulation model that was consistent with the method as described in the above narrative section titled BGH GP Holdings, LLC Override Units .

2009 Nonqualified Deferred Compensation Table

Name (a)	Registrant Contributions in Last Fiscal Year ($) (1)	Aggregate Gains in Last Fiscal Year ($)	Aggregate Withdrawals in Last Fiscal Year ($)	Aggregate Balance at Last Fiscal Year ($) (2)
Forrest E. Wylie	16,269	7,033		38,227
Keith E. St.Clair	15,825	1,107		16,932
Clark C. Smith				
Robert A. Malecky	35,340	55,173		163,931
Khalid A. Muslih	13,699	6,712		32,128
Stephen C. Muther		149,505	547,665	

(1) These contributions in the last fiscal year for each named executive officer are included in the All Other Compensation column of the Summary Compensation Table above.

(2) The following amounts were previously reported as compensation in the Summary Compensation Table for previous years:

Mr. Wylie
$17,000 and
Mr. Muther
$41,671.

The amounts reflected in the table above were credited to accounts of the named executive officers under the Benefit Equalization Plan. The Benefit Equalization Plan is a non-qualified deferred compensation plan and provides that any employee whose company contributions to qualified pension and savings plans have been limited due to IRS limits on compensation allowable for calculating benefits under qualified plans will receive an equivalent benefit under the Benefit Equalization Plan for company contributed amounts they would have received under qualified plans if there were no IRS limits on compensation levels. Employee deferrals are not allowed under the Benefit Equalization Plan. In addition, the Benefit Equalization Plan provides that any employee with a balance in the plan will be credited with earnings on that balance at a rate that is equivalent to the actual earnings that the employee realizes on his or her investments in the Retirement and Savings Plan or his or her gains under the ESOP. The ESOP value is based on the LP Unit value. During 2009, the market price of LP Units increased by 66.7%. Employees may periodically change their investment elections in the Retirement and Savings Plan in accordance with its terms and the terms of the documents governing the investments in which they currently participate. Amounts accumulated by an employee in the Benefit Equalization Plan are payable to the employee, or their beneficiary, in a lump sum upon termination of employment or following death. All amounts are paid based on the timing and form set forth in the Benefit Equalization Plan. A participating employee may also receive a distribution of all or a portion of his or her account balance in the event of a hardship as defined in the plan document and upon determination by the committee that administers the plan.

The table below shows the fund options available under the Retirement and Savings Plan and their annual rate of return for the year ended December 31, 2009.

Name of Fund	Rate of Return
American Century Income & Growth Inst. Fund	18.20%
American Century Small Cap Value Inst. Fund	39.27%
American Funds Growth Fund of America R4	34.54%
American Value Portfolio	30.36%
JPMorgan SmartRetirement 2010-Inst.	23.57%
JPMorgan SmartRetirement 2015-Inst.	26.82%
JPMorgan SmartRetirement 2020-Inst.	29.39%
JPMorgan SmartRetirement 2030-Inst.	32.98%
JPMorgan SmartRetirement 2040-Inst.	33.87%
JPMorgan SmartRetirement Income-Inst.	21.62%
JPMorgan Stable Value	1.96%
Lord Abbett Developing Growth A Fund	47.03%
Oakmark Equity and Income Fund	19.84%
PIMCO Total Return Fund	13.58%
SSgA S&P500 Index SL-III	26.51%
SSgA International Index -SL-II	31.92%
Templeton Foreign A Fund	49.73%

Payments upon Termination or Change in Control

Severance Agreement Payments

We entered into a Severance Agreement in connection with the appointment of Mr. St.Clair as Senior Vice President and CFO of Buckeye GP, dated as of November 10, 2008, with BGH and Services Company. We also entered into a Severance Agreement in connection with the appointment of Mr. Smith as President and Chief Operating Officer of Buckeye GP, dated as of February 17, 2009, with BGH and Services Company. With the exception of the severance multiplier, 100% (or one times base salary) for Mr. St.Clair and 200% (or two times base salary) for Mr. Smith, the material terms of their respective Severance Agreements are identical.

Pursuant to the terms of the Severance Agreements, the executives are entitled to severance payments following (i) the termination of employment by Services Company except if the termination is a result of (x) the continuous illness, injury or incapacity for a period of six consecutive months, or (y) Cause , or (ii) a voluntary termination of employment by the executives upon (I) the material failure of Services Company to comply with and satisfy any of the terms of the Severance Agreement, (II) the significant reduction by Services Company of the authority, duties or responsibilities of the executives, (III) the elimination of the executives from eligibility to participate in, or the exclusion of the executives from participation in, employee benefit plans or policies, except to the extent such elimination or exclusion is applicable to our named executive officers as a group, (IV) the reduction in the executives annual base compensation or the reduction in the annual target cash bonus opportunity for which the executives are eligible (unless such reduction in the executives annual target cash bonus opportunity is made in connection with similar reductions in the bonus opportunities of our named executive officers as a group), or (V) the transfer of the executive, without his express written consent, to a location that is more than 100 miles from Houston, Texas (for Mr. St.Clair) or Breinigsville, Pennsylvania (for Mr. Smith).

Upon a termination as set forth above, each executive would be entitled to the following:

A lump-sum severance payment in the amount of (i) one times annual base salary for Mr. St.Clair (two times annual base salary for Mr. Smith), plus (ii) 100% of the annual bonus opportunity for Mr. St.Clair (200% of the annual bonus opportunity for Mr. Smith), for the applicable year.

Continued benefits under our medical and dental plans and policies for a period of 12 months for Mr. St.Clair (or 24 months for Mr. Smith). During the benefit period, Services Company will pay the executives a monthly payment equal to the COBRA cost of continued health and dental coverage, less the amount that the executive would be required to contribute for health and dental coverage if they were an active employee.

An additional tax gross-up amount equal to the federal, state and local income and payroll taxes, if any, that the executives incur on the benefit payment and the gross-up payment. For the purposes of the gross-up payment, the aggregate tax rate for the federal, state and local income and payroll taxes is assumed to be 25%. The gross-up payments will cease when the benefits payments cease.

For the purposes of the Severance Agreements, Cause is defined as (i) habitual insobriety or substance abuse, (ii) engaging in acts of disloyalty to Buckeye or BGH including fraud, embezzlement, theft, commission of a felony, or proven dishonesty, or (iii) willful misconduct of the executive in the performance of his duties, or the willful failure of the executive to perform a material function of his duties pursuant to the terms of the Severance Agreement.

Severance Pay Plan Payments

Messrs. Wylie, Malecky and Muslih do not have severance agreements but are eligible for severance payments under the Severance Pay Plan for Employees of Buckeye Pipe Line Services Company. Subject to certain limitations, upon an involuntary termination, Messrs. Wylie, Malecky and Muslih would be entitled to receive a lump-sum severance payment equal to eight weeks of their base pay plus two weeks base pay for each year of service over 4 years (the Severance Allowance). In the case of an involuntary termination within two years of a change of control (as defined in the plan), Messrs. Wylie, Malecky and Muslih would be entitled to receive either (i) one year s base salary, plus the Severance Allowance if they had completed 15 years or more of service, or (ii) two times the Severance Allowance if they had completed less than 15 years of service.

For the purposes of the severance pay plan, a change of control will occur if any person (as such term is used in sections 13(d) and 14(d) of the Exchange Act), except us or our affiliates becomes the beneficial owner, or the holder of proxies, in the aggregate of 80% or more of our LP Units then outstanding.

ESOP and Benefit Equalization Plan Payments

Upon termination of employment for any reason, each named executive officer would become entitled to distributions of the aggregate balances of his Benefits Equalization Plan account and ESOP account. If such officers had been terminated as of December 31, 2009, each of them would have been entitled to receive the amounts set forth opposite his name in the Aggregate Balance at Last Fiscal Year End column of the Nonqualified Deferred Compensation Table for his Benefits Equalization Plan balance. As of June 30, 2009 (the date of Mr. Muther s retirement), the value of Mr. Muther s ESOP account was $604,936 and, as of December 31, 2009 the value of Mr. Malecky ESOP account was $668,478. The ESOP and Benefit Equalization Plan termination payments are not set forth in the tables below.

Long-Term Incentive Plan

Upon a termination of employment for (i) death, (ii) disability, (iii) without cause during a change in control period, or (iv) resignation for good reason during a change in control period, each of our named executive officers are entitled to accelerated vesting of all phantom units, and performance units, based on a payout performance multiplier of 100%. Upon a termination of employment for cause or voluntary resignation, all unvested phantom units and performance units will be forfeited. If a named executive officer is terminated without cause, not during a change in control period, or retires, all phantom units vest based on the portion of the restriction period during which the named executive officer was employed by us, and all performance units will vest on a prorated portion based on the actual performance results of the performance period during which the named executive officer was employed by us.

A more detailed description of the 2009 LTIP is contained in the narrative discussion entitled Long-Term Incentive Plan following the Grant of Plan-Based Awards Table and in the Compensation Discussion and Analysis.

BGH GP Override Units

Upon a sale of a controlling interest in BGH or BGH GP, our named executive officers may be entitled to participate in a distribution in connection with an exit event as described above under the heading BGH GP Holdings, LLC Override Units. The amount of any such distribution is currently indeterminable, as it depends on the purchase price for the transaction and also on the aggregate amount of distributions that have been made to the ArcLight Kelso Members described above prior to the effective date of the sale.

As set forth above, certain percentages of each named executive officer s override units are subject to forfeiture upon the occurrence of certain events. Termination of employment of a named executive officer due to death, disability or retirement will not subject the Operating Units to any forfeiture, however.

Mr. Muther

On October 25, 2007, in connection with Mr. Muther becoming President of our general partner and of BGH s general partner, Mr. Muther and BGH amended and restated his employment and severance agreement. Mr. Muther s employment and severance agreement provides that BGH will pay severance payments and allow Mr. Muther to continue certain medical and dental benefits following a termination of Mr. Muther s employment by BGH (and its affiliates). Under the employment and severance agreement, Mr. Muther is entitled to the payment of severance and the continuation of certain benefits following (a) an involuntary termination of Mr. Muther s employment for any reason other than for cause or (b) a voluntary termination of employment by Mr. Muther for good reason, which includes an election by Mr. Muther to terminate his employment between December 26, 2008 and June 25, 2010 following a change of control in us or BGH (which includes the change of control that occurred on June 25, 2007). Under either of these circumstances, Mr. Muther would receive a cash severance payment from BGH of $2,000,000 at the time of his termination. Mr. Muther had a qualifying termination of employment on June 30, 2009 and received a lump-sum severance payment equal to $2,000,000 from BGH. In addition, BGH agreed to provide certain continued medical and dental benefits to Mr. Muther under our plans for a period of 18 months following his termination (36 months if his termination were to be in connection with a change of control, which includes the change of control that ocurred on June 25, 2007). Mr. Muther s eligibility to continue receiving these medical and dental benefits will cease if Mr. Muther obtains new employment that provides him with eligibility for medical benefits without a pre-existing condition limitation.

For purposes of Mr. Muther s employment agreement, a change of control is defined as the acquisition (other than by our general partner and its affiliates) of 80% or more of our LP Units, 51% or more of the general partner interests owned by our general partner or 50% or more of the voting equity interest of us and our general partner on a combined basis and includes the change of control that occurred on June 25, 2007.

Payments upon Termination or Change in Control Tables

The tables below reflect the compensation and benefits, if any, due to each of the named executive officers upon a voluntary termination, a termination for cause, an involuntary termination other than for cause or resignation for good reason, both before and after a change of control, a change of control, or a termination due to death, disability or retirement. The amounts shown assume that each termination of employment or the change of control, as applicable, was effective as of December 31, 2009, and the fair market value of an LP Unit as of December 31, 2009 was $54.56, based on the average high and low sale price. The amounts shown in the table are estimates of the amounts which would be paid upon termination of employment or change of control, as applicable. The actual amounts to be paid can only be determined at the time of the actual termination of employment or change of control, as applicable. The tables do not include amounts payable under the ESOP or the Benefit Equalization Plan as such amounts are not subject to forfeiture and are payable upon any termination of employment. Mr. Muther is not included in the tables because he resigned effective February 17, 2009 and would not be entitled to any compensation or benefits upon a termination or change in control as of December 31, 2009.

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The value of the accelerated vesting of unit options was calculated by multiplying the number of unvested units subject to each option by the difference between the fair market value of an LP Unit as of December 31, 2009, and the per unit exercise price of the option. The value of the accelerated vesting and payment of phantom units was calculated by multiplying the aggregate number of phantom units by the fair market value of an LP Unit as of December 31, 2009, taking into account months of service over the 36 month vesting period as applicable for certain prorated payouts. The value of the accelerated vesting and payment of performance units was calculated by multiplying the aggregate number of performance units by the fair market value of an LP Unit as of December 31, 2009, taking into account months of service over the 36 month performance period based on a payout performance multiplier of 100%. More details concerning these values are set forth in the footnotes below.

Name and Benefit	Voluntary Resignation or Termination for Cause	Termination Without Cause Prior to Change in Control	Resignation for Good Reason Before Change in Control	Resignation for Good Reason After Change in Control	Change in Control	Termination Without Cause After Change in Control	Death, Disability or Retirement
Forrest E. Wylie:							
Cash Severance (1)	$	$ 61,538	$	$	$	$ 123,077	$
Option Acceleration							
Phantom Unit Acceleration (2)		57,791		260,087		260,087	260,087
Performance Unit Acceleration (3)		115,594		520,175		520,175	520,175
Health Benefits							
Keith E. St.Clair:							
Cash Severance (4)		650,000	650,000	650,000		650,000	
Option Acceleration							
Phantom Unit Acceleration (5)		44,654		200,944		200,944	200,944
Performance Unit Acceleration (6)		89,321		401,943		401,943	401,943
Health Benefits (7)		15,132	15,132	15,132		15,132	
Clark C. Smith:							
Cash Severance (8)		1,300,000	1,300,000	1,300,000		1,300,000	
Option Acceleration							
Phantom Unit Acceleration (9)		47,285		212,784		212,784	212,784
Performance Unit Acceleration (10)		94,570		425,568		425,568	425,568
Health Benefits (11)		30,264	30,264	30,264		30,264	
Robert A. Malecky:							
Cash Severance (12)		196,839				440,545	
Option Acceleration (13)		146,000			146,000		146,000
		15,761		70,928		70,928	70,928

Phantom Unit Acceleration (14)					
Performance Unit Acceleration (15)	31,523	141,856		141,856	141,856
Health Benefits					
Khalid A. Muslih:					
Cash Severance (1)	34,615			69,231	
Option Acceleration (16)	25,450		25,450		25,450
Phantom Unit Acceleration (17)	15,761	70,928		70,928	70,928
Performance Unit Acceleration (18)	31,523	141,856		141,856	141,856
Health Benefits					

(1) The cash severance payments to Messrs. Wylie and Muslih are paid under the Severance Pay Plan for Employees of Buckeye Pipe Line Services Company. Mr. Wylie and Mr. Muslih are entitled to receive a lump-sum severance payment equal to eight weeks of their base pay for a termination without cause before

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a change in control or sixteen weeks of their base pay for a termination without cause after a change in control.

(2) This amount represents the value of the accelerated vesting and payment of 4,767 phantom units based on a price per LP Unit as of December 31, 2009 of $54.56. In the event of termination without cause or due to retirement, Mr. Wylie would not be entitled to full accelerated vesting but instead would be entitled to a prorated amount based on 8 months of service over the 36 month service period (8/36th), multiplied by $260,087, or $57,791.

(3) This amount represents the value of the accelerated

vesting and payment, assuming 9,534 performance units, calculated on a payout performance multiplier of 100%, based on a price per LP Unit as of December 31, 2009 of $54.56. In the event of termination without cause or due to retirement, Mr. Wylie would not be entitled to full accelerated vesting but instead would be entitled to a prorated amount based on 8 months of service over the 36 month service period (8/36th), multiplied by $520,175, or $115,594.

(4) Pursuant to the terms of his Severance Agreement, Mr. St.Clair is entitled to one (1) times his annual base salary, $325,000, plus the full amount of his annual target cash bonus award, $325,000, for a

total of $650,000 payable in a lump sum.

(5) This amount represents the value of the accelerated vesting and payment of 3,683 phantom units based on a price per LP Unit as of December 31, 2009 of $54.56. In the event of termination without cause or due to retirement, Mr. St.Clair would not be entitled to full accelerated vesting but instead would be entitled to a prorated amount based on 8 months of service over the 36 month service period (8/36th), multiplied by $200,944, or $44,654.

(6) This amount represents the value of the accelerated vesting and payment, assuming 7,367 performance units, calculated on a payout performance

multiplier of 100%, based on a price per LP Unit as of December 31, 2009 of $54.56. In the event of termination without cause or due to retirement, Mr. St.Clair would not be entitled to full accelerated vesting but instead would be entitled to a prorated amount based on 8 months of service over the 36 month service period (8/36th), multiplied by $401,943, or $89,321.

(7) This amount is equal to 12 months of continued health benefits assuming a monthly cost of $1,261 as set forth in Mr. St.Clair s Severance Agreement. Mr. St.Clair is also entitled to an additional tax gross-up amount equal to the federal, state and local income and payroll taxes, if any, that

Mr. St.Clair incurs on the benefit payment and the gross-up payment. The tax-gross up amount is not included in this calculation.

(8) Pursuant to the terms of his Severance Agreement, Mr. Smith is entitled to two (2) times his annual base salary, $650,000, plus 200% of his annual target cash bonus award, $650,000, for a total of $1,300,000 payable in a lump sum.

(9) This amount represents the value of the accelerated vesting and payment of 3,900 phantom units based on a price per LP Unit as of December 31, 2009 of $54.56. In the event of termination without cause or due to retirement, Mr. Smith would not be entitled to full accelerated

vesting but instead would be entitled to a prorated amount based on 8 months of service over the 36 month service period (8/36th), multiplied by \$212,784, or \$47,285.

(10) This amount represents the value of the accelerated vesting and payment, assuming 7,800 performance units, calculated on a payout performance multiplier of 100%, based on a price per LP Unit as of December 31, 2009 of \$54.56. In the event of termination without cause or due to retirement, Mr. Smith would not be entitled to full accelerated vesting but instead would be entitled to a prorated amount based on 8 months of service over the 36 month service period (8/36th), multiplied by

$425,568, or $94,570.

(11) This amount is equal to 24 months of continued health benefits assuming a monthly cost of $1,261 as set forth in Mr. Smith s Severance Agreement. Mr. Smith is also entitled to an additional tax gross-up amount equal to the federal, state and local income and payroll taxes, if any, that Mr. Smith incurs on the benefit payment and the gross-up payment. The tax-gross up amount is not included in this calculation.

(12) The cash severance payments to Mr. Malecky are paid under the Severance Pay Plan for Employees of Buckeye Pipe Line Services Company. Mr. Malecky would be entitled to receive a lump-sum

severance payment equal to 42 weeks of his base pay for a termination without cause before a change in control or one year and 42 weeks of his base pay for a termination without cause after a change in control.

(13) This amount represents the value of unvested unit options to purchase an aggregate of 12,000 LP Units based on a price per LP Unit as of December 31, 2009 of $54.56.

(14) This amount represents the value of the accelerated vesting and payment of 1,300 phantom units based on a price per LP Unit as of December 31, 2009 of $54.56. In the event of termination without cause or due to retirement, Mr. Malecky would not be entitled to full accelerated vesting but

instead would
be entitled to a

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prorated amount based on 8 months of service over the 36 month service period (8/36th), multiplied by $70,928 or $15,761.

(15) This amount represents the value of the accelerated vesting and payment, assuming 2,600 performance units, calculated on a payout performance multiplier of 100%, based on a price per LP unit as of December 31, 2009 of $54.56. In the event of termination without cause or due to retirement, Mr. Malecky would not be entitled to full accelerated vesting but instead would be entitled to a prorated amount based on 8 months of service over the 36 month service period (8/36th), multiplied by $141,856, or

$31,523.

(16) This amount represents the value of unvested unit options to purchase an aggregate of 5,000 LP Units based on a price per LP Unit as of December 31, 2009 of $54.56.

(17) This amount represents the value of the accelerated vesting and payment of 1,300 phantom units based on a price per LP Unit as of December 31, 2009 of $54.56. In the event of termination without cause or due to retirement, Mr. Muslih would not be entitled to full accelerated vesting but instead would be entitled to a prorated amount based on 8 months of service over the 36 month service period (8/36th), multiplied by $70,928 or $15,761.

(18)

This amount represents the value of the accelerated vesting and payment, assuming 2,600 performance units, calculated on a payout performance multiplier of 100%, based on a price per LP Unit as of December 31, 2009 of $54.56. In the event of termination without cause or due to retirement, Mr. Muslih would not be entitled to full accelerated vesting but instead would be entitled to a prorated amount based on 8 months of service over the 36 month service period (8/36th), multiplied by $141,856, or $31,523.

2009 Director Compensation Table

Name	Fees Earned or Paid in Cash	Unit Awards (1)	Other Compensation (2)	Total
Irvin K. Culpepper	$	$	$	$
John F. Erhard				
Michael B. Goldberg				
C. Scott Hobbs	91,250	117,165	8,213	216,628
Mark C. McKinley	75,000	117,165	8,213	200,378
Oliver Rick G. Richard, III	78,125	117,165	8,213	203,503

Robb E. Turner

(1) Amounts reflect the aggregate grant date fair value (computed in accordance with FASB ASC Topic 718) of phantom unit awards under the 2009 LTIP in 2009. For a discussion of the valuations of phantom units, please see the discussion in Note 18 in the Notes to Consolidated Financial Statements. As of December 31, 2009, Messrs. Hobbs, McKinley and Richard each held 3,000 phantom units.

(2) Amounts represent the distribution equivalents paid during 2009 on unvested phantom unit awards granted under the 2009 LTIP.

Director Compensation

In 2009, directors of Buckeye GP received an annual fee in cash of $50,000 plus $1,250 for each Board of Directors and committee meeting attended. Each director also received a grant under the 2009 LTIP of 3,000 phantom units which vest on the first anniversary date of the date of grant, or April 30, 2010. Additionally, the Chairman of the Audit Committee and Compensation Committees each receive an annual fee of $10,000. Neither Mr. Wylie, nor any of the non-independent members of the Board of Directors receive any fees for services as a director. For the portion of 2009 prior to February 17, 2009, Mr. Smith served as an independent director and received fees totaling $8,750, which are reflected in the Summary Compensation Table above. In 2009, the Buckeye GP Director Recognition Program, which provided benefits to directors upon death or retirement in certain circumstances, was terminated. Directors fees paid by our general partner in 2009 to its directors were $223,125. We reimbursed our general partner for the directors fees.

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

Services Company owns approximately 3.1% of our outstanding LP Units as of February 18, 2010. No person or group is known to be the beneficial owner of more than 5% of our LP Units as of February 18, 2010.

The following table sets forth certain information, as of February 18, 2010, concerning the beneficial ownership of our LP Units by each director of our general partner, the CEO of our general partner, the President and Chief Operating Officer of our general partner, the other named executive officers of our general partner and by all directors and executive officers of our general partner as a group. The number of LP Units in the table below includes LP Units issuable upon the exercise of outstanding equity grants to the extent that such grants are exercisable by the respective directors, named executive officers and the executive officers, as the case may be, on or within 60 days after February 18, 2010. Based on information furnished to our general partner by such persons, no director, named executive officer or executive officer of our general partner owned beneficially, as of such date, more than 1% of any class of our equity securities. All information with respect to beneficial ownership has been furnished by the respective directors, named executive officers and executive officers, as the case may be. The address for the individuals and entities for which an address is not otherwise indicated is: c/o Buckeye Partners, L.P., One Greenway Plaza, Suite 600, Houston, TX 77046.

Name	Number of LP Units (1)
Buckeye GP Holdings L.P.	80,000 (2)
Irvin K. Culpepper, Jr.	
John F. Erhard	80,000 (2)
Michael B. Goldberg	
C. Scott Hobbs	10,000
Robert A. Malecky	33,900 (3)
Mark C. McKinley	2,000
Khalid A. Muslih	
Stephen C. Muther	24,300 (4)
Oliver G. Rick Richard, III	750
Clark C. Smith	3,000 (5)
Keith E. St. Clair	
Robb E. Turner	80,000 (2)
Forrest E. Wylie	82,500 (2)
All directors and executive officers as a group (consisting of 13 persons)	137,150 (6)

(1) Unless otherwise indicated, the persons named above have sole voting and investment power over the LP Units reported.

(2) Includes the 80,000 LP Units owned by BGH,

over which the indicated persons share voting and investment power by virtue of their membership on the Board of Directors of MainLine Management, the general partner of BGH. Such individuals expressly disclaim beneficial ownership of such LP Units.

(3) Mr. Malecky shares investment and voting power over the 9,500 LP Units with his wife. Amount also includes 24,400 LP Units issuable upon exercise of outstanding options.

(4) Effective February 17, 2009, Mr. Muther resigned from his position as President of Buckeye GP due to his pending retirement. Mr. Muther continued as an employee of Services

Company through June 30, 2009.

(5) Mr. Smith shares investment and voting power over the 3,000 LP Units with his wife.

(6) The 80,000 LP Units owned by BGH are included in the total only once. Amount also includes 27,400 LP Units issuable upon exercise of outstanding options.

The following table sets forth certain information, as of February 18, 2010, concerning the beneficial ownership of the Common and Management Units of BGH held by each director of our general partner, the CEO of our general partner, the President and Chief Operating Officer of our general partner, the other named executive officers of our general partner and by all directors and executive officers of our general partner as a group. All information with

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respect to beneficial ownership has been furnished by the respective directors, named executive officers and executive officers, as the case may be. The address for the individuals and entities for which an address is not otherwise indicated is: c/o Buckeye Partners, L.P., One Greenway Plaza, Suite 600, Houston, TX 77046.

Name of Beneficial Owner:	Number of BGH Common & Management Units (1)	Percent of Common & Management Units
Irvin K. Culpepper, Jr.		
John F. Erhard		
Michael B. Goldberg		
C. Scott Hobbs		
Robert A. Malecky	45,000	*(2)
Mark C. McKinley		
Khalid A. Muslih		
Stephen C. Muther	47,900	*(3)
Oliver G. Rick Richard, III		
Clark C. Smith		
Keith E. St.Clair		
Robb E. Turner	17,513,737	61.9%(4)(5)
Forrest E. Wylie	17,513,737	61.9%(4)(5)
All directors and executive officers as a group (consisting of 13 persons)	17,559,737	62.0%(6)

* Less than 1%.

(1) Unless otherwise indicated, the persons named above have sole voting and investment power over the Common and Management Units reported.

(2) Mr. Malecky shares investment and voting power over 28,157 Common Units with his wife.

(3) Effective February 17,

2009, Mr. Muther resigned from his position as President of Buckeye GP due to his pending retirement which occurred on June 30, 2009.

(4) Includes Management Units, which are convertible into Common Units, at the election of the holder, on a one-for-one basis.

(5) Includes Common and Management Units owned by BGH GP, the sole member of Mainline Management. BGH GP is governed by a board of directors which includes Messrs. Turner and Wylie, each of whom is also a director of BGH s general partner. Therefore, each of these directors has shared voting and investment power over the securities indicated. BGH GP is primarily

owned by investment partnerships affiliated with ArcLight, Kelso and certain investment funds. The address of BGH GP is c/o ArcLight Capital Partners, LLC, 200 Clarendon Street, 55th Floor, Boston, Massachusetts 02117. Each of Messrs. Turner, and Wylie expressly disclaims beneficial ownership of such Common and Management Units of BGH.

(6) The 17,513,737 Common and Management Units are included in the total only once.

Equity Compensation Plan Information

The following table sets forth information as of December 31, 2009 with respect to compensation plans under which our equity securities are authorized for issuance.

Plan Category	Number of LP Units to be issued upon exercise of outstanding LP Unit options and rights (a)	Weighted-average exercise price of outstanding LP Unit options and rights	Number of LP Units remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by Unitholders: (1)			
2009 LTIP (2)	140,095	$	1,359,386
Option Plan	349,400	46.25	379,600
Equity compensation plans not approved by Unitholders			
Total for equity compensation plans	489,495	$ 46.25	1,738,986

(1) See Note 18 in the Notes to Consolidated Financial Statements for further information about these plans.

(2) The 140,095 represents 57,911 phantom units and 82,184 performance units issued under the 2009 LTIP. See Note 18 in the Notes to Consolidated Financial Statements and Item 11.

Executive Compensation for further information about these awards. These awards are not taken into account in the calculation of the weighted-average exercise price of outstanding options and rights under the 2009 LTIP.

Changes in Control

BGH is party to a $10.0 million credit agreement with SunTrust Bank. We are not a party to this credit agreement. BGH s credit agreement is secured by the pledge of the outstanding limited liability company interests of our general partner. If BGH defaults on its obligations under its credit agreement, the lender could exercise its rights under this pledge, which could result in a future change of control of us.

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

General Partner Reimbursement and Distributions

Reimbursement of General Partner Costs and Expenses

Our general partner manages us and our Operating Subsidiaries that are limited partnerships pursuant to our partnership agreement, the several Amended and Restated Agreements of Limited Partnership of those Operating Subsidiaries and the several Management Agreements between an affiliate of our general partner and those Operating Subsidiaries. Under these agreements, and the limited liability company agreements of our Operating Subsidiaries that are limited liability companies, our general partner and certain related parties are entitled to reimbursement of all direct and indirect costs and expenses related to managing us and our Operating Subsidiaries, except as otherwise provided by the Exchange Agreement (as discussed below).

As part of a restructuring of our ESOP in 1997, we and certain of our Operating Subsidiaries entered into an Exchange Agreement with our general partner s predecessors, pursuant to which we and our Operating Subsidiaries were permanently released from our obligations to reimburse the general partner for certain compensation and fringe benefit costs for executive level duties performed by our general partner with respect to operations, finance, legal, marketing and business development, and treasury, as well as the President of our general partner (but excluding certain of our obligations to pay severance and certain retirement obligations that had accrued for the benefit of such persons prior to the date of the exchange agreement). In connection with a restructuring of the general partner in

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2004, the Exchange Agreement was amended to provide that such release included the compensation and fringe benefit costs for the four highest salaried officers performing duties for our general partner. Commencing January 1, 2009, we agreed to reassume all liability to pay the compensation of such officers, and, in return for such assumption, BGH pays to us a fixed annual payment of $3.6 million.

Management Fee

BGH s general partner is entitled to be paid an annual management fee for certain management functions it provides to our general partner pursuant to a Management Agreement between it and our general partner. Our general partner charges the management fee to us. The management fee includes an annual Senior Administrative Charge of not less than $975,000 and reimbursement for certain costs and expenses. The disinterested directors of our general partner approve the amount of the management fee on an annual basis. In connection with the acquisition of all of the member interests in Lodi Gas from Lodi Holdings, L.L.C., an affiliate of ArcLight, MainLine Management, the general partner of BGH, agreed to forego payment of the Senior Administrative Charge effective June 25, 2007 through 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.

Distribution Rights

Our general partner is entitled to receive distributions from us. Our general partner s approximate 0.5% general partner interest in us entitles it to receive approximately 0.5% of the cash we distribute to our partners each quarter other than incentive distribution payments. Additionally, our general partner is entitled to receive incentive distributions from us. Pursuant to our partnership agreement and the Fifth Amended and Restated Incentive Compensation Agreement between our general partner and us, subject to certain limitations and adjustments, if a quarterly cash distribution exceeds a target of $0.325 per LP Unit, we will pay our general partner, in respect of each outstanding LP Unit, incentive compensation equal to (i) 15% of that portion of the distribution per LP Unit which exceeds the target quarterly amount of $0.325 but is not more than $0.35, plus (ii) 25% of the amount, if any, by which the quarterly distribution per LP Unit exceeds $0.35 but is not more than $0.375, plus (iii) 30% of the amount, if any, by which the quarterly distribution per LP Unit exceeds $0.375 but is not more than $0.40, plus (iv) 35% of the amount, if any, by which the quarterly distribution per LP Unit exceeds $0.40 but is not more than $0.425, plus (v) 40% of the amount, if any, by which the quarterly distribution per LP Unit exceeds $0.425 but is not more than $0.525, plus (vi) 45% of the amount, if any, by which the quarterly distribution per LP Unit exceeds $0.525. Our general partner is also entitled to an incentive distribution, under a comparable formula, in respect of special cash distributions exceeding a target special distribution amount per LP Unit. The target special distribution amount generally means the amount which, together with all amounts distributed per LP Unit prior to the special distribution compounded quarterly at 13% per annum, would equal $10.00 (the initial public offering price of the LP Units split two-for-one) compounded quarterly at 13% per annum from the date of the closing of our initial public offering in December 1986. Incentive payments paid by us for quarterly cash distributions totaled approximately $45.7 million, $38.9 million and $30.0 million during the years ended December 31, 2009, 2008 and 2007, respectively. No special cash distributions have ever been paid by us.

Ownership of Buckeye GP Holdings L.P.

BGH owns our general partner, and, therefore, benefits from payments made by us to our general partner, such as the distributions described above. Because BGH distributes substantially all of its available cash to its unitholders quarterly and because certain members of management receive these distributions as unitholders of BGH, these members of management may have an indirect material interest in such payments.

Policies Regarding Related Party Transactions

Except for compensation that we pay, the material portions of which are described in this Report, our policy is to avoid transactions between us and our directors and officers (including members of their families) in which such persons would have a material interest. In furtherance of this policy, we have adopted Corporate Governance Guidelines, a Code of Ethics for Directors, Executive Officers and Senior Financial Employees and a Business Code of Conduct for all employees, which generally require the reporting to management of transactions or opportunities that constitute conflicts of interest so that they may be avoided. These guidelines and codes are available on our website at *www.buckeye.com* by browsing to the Corporate Governance subsection of the Investor Center menu.

We also have a policy of avoiding transactions between us and holders of 5% or more of our LP Units.

Pursuant to our Corporate Governance Guidelines, any transaction between us and our officers and directors or holders of 5% of more of our LP Units that should be avoided pursuant to these policies must be reviewed and approved by the Board of Directors of Buckeye GP (other than any board member having a material interest in the transaction in question). The Board of Directors of Buckeye GP will only approve transactions that are fair and reasonable to us. Our partnership agreement states that a transaction will be deemed fair and reasonable to us if it is approved by our Audit Committee, if it is on terms objectively demonstrable to be no less favorable to us than those generally being provided to or available from unrelated third parties, or if it is otherwise determined to be fair to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

Director Independence

Section 303A.00 of the NYSE Listed Company Manual states that the NYSE listing standards requiring a majority of directors to be independent do not apply to publicly traded limited partnerships like us. However, three of Buckeye GP s eight directors are independent as that term is defined in the applicable NYSE rules and Rule 10A-3 of the Exchange Act. In determining the independence of each director, our general partner has adopted certain categorical standards. Buckeye GP s independent directors as determined in accordance with those standards, are C. Scott Hobbs, Mark C. McKinley and Oliver G. Rick Richard, III. Pursuant to such categorical standards, a director will not be deemed independent if:

- the director is, or has been within the last three years, our employee, or an immediate family member is, or has been within the last three years, our executive officer;

- the director has received, or has an immediate family member who has received, during any twelve-month period within the last three years, more than $120,000 in direct compensation from us, other than director and committee fees and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service);

- (i) the director or an immediate family member is a current partner of a firm that is our internal or external auditor; (ii) the director is a current employee of such a firm; (iii) the director has an immediate family member who is a current employee of such a firm and who participates in the firm s audit, assurance or tax compliance (but not tax planning) practice; or (iv) the director or an immediate family member was within the last three years (but is no longer) a partner or employee of such a firm and personally worked on our audit within that time;

- the director or an immediate family member is, or has been within the last three years, employed as an executive officer of another company where any of our present executive officers at the same time serve or served on that company s Compensation Committee;

- the director is a current employee, or an immediate family member is a current executive officer, of a company that has made payments to, or received payments from, us for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of $1.0 million, or 2% of such other company s consolidated gross revenues; or

the director serves as an executive officer of a charitable organization and, during any of the past three fiscal years, we made charitable contributions to the charitable organization in any single fiscal year that exceeded $1.0 million or 2%, whichever is greater, of the charitable organization s consolidated gross revenues.

For the purposes of these categorical standards, the term immediate family member includes a person s spouse, parents, children, siblings, mothers and fathers-in-law, sons and daughters-in-law, brothers and sisters-in-law, and anyone (other than domestic employees) who shares such person s home.

Item 14. *Principal Accounting Fees and Services*

We have engaged Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatus, and their respective affiliates (collectively, Deloitte & Touche) as our independent registered public accounting firm and principal accountants. The following table summarizes the aggregate fees billed to us by Deloitte & Touche for independent auditing, tax and related services for each of the last two fiscal years:

	Year Ended December 31,	
	2009	**2008**
Audit fees (1)	$ 1,499,725	$ 1,879,182
Audit- related fees (2)	85,000	85,000
Tax fees (3)	376,547	815,329
All other fees (4)		
Total	$ 1,961,272	$ 2,779,511

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the audit of our annual financial statements and internal control over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and

regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this Report.

(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly review. This category primarily includes services relating to fees for audits of financial statements of certain employee benefits plans.

(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with

tax compliance, tax advice and tax planning. This category primarily includes services relating to the preparation of Unitholder annual K-1 statements and partnership tax planning.

(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above. No such services were rendered by Deloitte & Touche during the last two years.

Procedures for Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Registered Public Accountant

As outlined in its charter, the Audit Committee of the Board of Directors is responsible for reviewing and approving, in advance, any audit and any permissible non-audit engagement or relationship between us and our independent auditors. Deloitte & Touche s engagement to conduct our audit was pre-approved by the Audit Committee. Additionally, all permissible non-audit services by Deloitte & Touche have been reviewed and pre-approved by the Audit Committee, as outlined in the pre-approval policies and procedures established by the Audit Committee.

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PART IV

Item 15. *Exhibits, Financial Statement Schedules*

(a) The following documents are filed as a part of this Report:

(1) Financial Statements see Index to Consolidated Financial Statements.

(2) Financial Statement Schedules None.

(3) Exhibits, including those incorporated by reference. The following is a list of exhibits filed as part of this Report.

Exhibit Number	Description
2.1	Purchase and Sale Agreement, dated as of July 24, 2007, by and between Lodi Holdings, L.L.C., as seller, and Buckeye Gas Storage LLC, as buyer (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on July 24, 2007).
2.2	Amendment No. 1 to the Purchase and Sale Agreement, dated as of October 31, 2007, by and between Lodi Holdings, L.L.C. and Buckeye Gas Storage LLC (Incorporated by reference to Exhibit 2.2 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on January 18, 2008).
2.3	Amendment No. 2 to the Purchase and Sale Agreement, dated as of November 13, 2007, by and between Lodi Holdings, L.L.C. and Buckeye Gas Storage LLC (Incorporated by reference to Exhibit 2.3 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on January 18, 2008).
2.4	Purchase Agreement, dated as of December 21, 2007, by and among Farm & Home Oil Company, Richard A. Longacre, as sellers representative and Buckeye Energy Holdings LLC (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on December 21, 2007).
3.1	Amended and Restated Agreement of Limited Partnership of Buckeye Partners, L.P., dated as of April 14, 2008, effective as of January 1, 2007 (Incorporated by reference to Exhibit 3.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on April 15, 2008).
3.2	Amended and Restated Certificate of Limited Partnership of the Partnership, dated as of February 4, 1998 (Incorporated by reference to Exhibit 3.2 of Buckeye Partners, L.P. s Annual Report on Form 10-K for the year ended December 31, 1997).
3.3	Certificate of Amendment to Amended and Restated Certificate of Limited Partnership of the Partnership, dated as of April 26, 2002 (Incorporated by reference to Exhibit 3.2 of Buckeye Partners, L.P. s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2002).
3.4	Certificate of Amendment to Amended and Restated Certificate of Limited Partnership of the Partnership, dated as of June 1, 2004, effective as of June 3, 2004 (Incorporated by reference to Exhibit 3.3 of the Buckeye Partners, L.P. s Registration Statement on Form S-3 filed June 16, 2004).
3.5	Certificate of Amendment to Amended and Restated Certificate of Limited Partnership of the Partnership, dated as of December 15, 2004 (Incorporated by reference to Exhibit 3.5 of Buckeye Partners, L.P. s Annual Report on Form 10-K for the year ended December 31, 2004).

4.1	Indenture dated as of July 10, 2003, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Registration Statement on Form S-4 filed September 19, 2003).

4.2	First Supplemental Indenture dated as of July 10, 2003, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.2 of Buckeye Partners, L.P. s Registration Statement on Form S-4 filed September 19, 2003).
4.3	Second Supplemental Indenture dated as of August 19, 2003, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.3 of Buckeye Partners, L.P. s Registration Statement on Form S-4 filed September 19, 2003).
4.4	Third Supplemental Indenture dated as of October 12, 2004, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on October 14, 2004).
4.5	Fourth Supplemental Indenture dated as of June 30, 2005, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on June 30, 2005).
4.6	Fifth Supplemental Indenture dated as of January 11, 2008, between Buckeye Partners, L.P. and U.S. Bank National Association (successor to SunTrust Bank), as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on January 11, 2008).
4.7	Sixth Supplemental Indenture dated as of August 18, 2009, between Buckeye Partners, L.P. and U.S. Bank National Association (successor-in-interest to SunTrust Bank), as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on August 24, 2009).
10.1	Amended and Restated Agreement of Limited Partnership of Buckeye Pipe Line Company, L.P., as amended and restated as of August 9, 2006 (Incorporated by reference to Exhibit 10.2 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on August 14, 2006). (1)
10.2	Amended and Restated Management Agreement of Buckeye Pipe Line Company, L.P., as amended and restated as of August 9, 2006 (Incorporated by reference to Exhibit 10.3 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on August 14, 2006). (2)
10.3	Limited Liability Company Agreement of Wood River Pipe Lines LLC, dated as of September 27, 2004 (Incorporated by reference to Exhibit 10.3 of Buckeye Partners, L.P. s Annual Report on Form 10-K for the year ended December 31, 2004).
10.4	Services Agreement dated as of December 15, 2004, among Buckeye Partners, L.P., the Operating Subsidiaries and Services Company (Incorporated by reference to Exhibit 10.3 of Buckeye Partners, L.P. s Current Report on Form 8-K dated December 20, 2004).
10.5	First Amendment to Services Agreement, dated as of October 15, 2008, among Buckeye Partners, L.P., Buckeye Pipe Line Services Company, and the subsidiary partnerships and limited liability companies of Buckeye set forth on the signature pages thereto. (Incorporated by reference to Exhibit 10.2 of Buckeye Partners, L.P. s Current Report on Form 8-K dated October 16, 2008).
10.6	Fifth Amended and Restated Exchange Agreement, dated as of October 15, 2008, among Buckeye GP Holdings L.P., Buckeye GP LLC, Buckeye Partners, L.P., MainLine L.P., Buckeye Pipe Line Company, L.P., Laurel Pipe Line Company, L.P., Everglades Pipe Line Company, L.P., and Buckeye Pipe Line

	Holdings, L.P. (Incorporated by reference to Exhibit 10.6 of Buckeye Partners, L.P. s Annual Report on Form 10-K for the year ended December 31, 2008).
*10.7	Amended and Restated Employment and Severance Agreement, dated as of October 25, 2007, by and among Stephen C. Muther, Buckeye GP Holdings L.P. and Buckeye Pipe Line Services Company (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on October 26, 2007).

*10.8	Severance Agreement, dated as of November 10, 2008, by and among Buckeye Partners, L.P., Buckeye GP Holdings L.P., Buckeye Pipe Line Services Company, and Keith E. St.Clair (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on November 10, 2008).
*10.9	Severance Agreement, dated as of February 17, 2009, by and among Buckeye Partners, L.P., Buckeye Pipe Line Services Company, and Clark C. Smith (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on February 17, 2009).
*10.10	Amended and Restated Unit Option and Distribution Equivalent Plan of Buckeye Partners, L.P., dated as of April 1, 2005 (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on April 4, 2005).
*10.11	Fifth Amended and Restated Incentive Compensation Agreement, dated as of August 9, 2006, between Buckeye Partners, L.P. and Buckeye GP LLC (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on August 14, 2006).
*10.12	Buckeye Partners, L.P. 2009 Long-Term Incentive Plan, as amended (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2009).
*/**10.13	Buckeye Partners, L.P. Annual Incentive Compensation Plan, as amended and restated, effective as of January 1, 2010.
*10.14	Deferral Unit and Incentive Plan (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on December 17, 2009).
*10.15	Full Waiver and Release of Claims, dated as of Mary 8, 2009, by Vance E. Powers (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2009).
10.16	Credit Agreement, dated November 13, 2006, among Buckeye Partners, L.P., as borrower, SunTrust Bank, as administrative agent, and the lenders signatory thereto (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on November 16, 2006).
10.17	First Amendment to Credit Agreement, dated as of May 18, 2007, by and among Buckeye Partners, L.P., as borrower, SunTrust Bank, as administrative agent, and the lenders signatory thereto (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2007).
10.18	Second Amendment to Credit Agreement, dated August 24, 2007, among Buckeye Partners, L.P., SunTrust Bank, as administrative agent, and the lenders signatory thereto (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Form Current Report on 8-K filed on August 28, 2007).
10.19	Third Amendment to Credit Agreement, dated January 23, 2008, among Buckeye Partners, L.P., SunTrust Bank, as administrative agent, and the lenders signatory thereto (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on January 28, 2008).

10.20	Fourth Amendment to Credit Agreement, dated August 21, 2009, among Buckeye Partners, L.P., SunTrust Bank, as administrative agent, and the lenders signatory thereto (Incorporated by reference to Exhibit 10.2 of Buckeye Partners, L.P. s Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2009).
10.21	Credit Agreement, dated as of May 20, 2008, by and among Farm & Home Oil Company LLC, 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 May 23, 2008).
10.22	First Amendment, dated as of July 18, 2008, to the Credit Agreement, dated as of May 20, 2008, among Farm & Home Oil Company LLC, 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 22, 2008).

10.23	Second Amendment and Increase Agreement, dated as of September 15, 2008, to the Credit Agreement, dated as of May 20, 2008, among Farm & Home Oil Company LLC, Buckeye Energy Services LLC, BNP Paribas and other lenders party thereto (Incorporated by reference to Exhibit 10.20 of Buckeye Partners, L.P. s Annual Report on Form 10-K for the year ended December 31, 2008).
10.24	Third Increase Agreement and Waiver, dated as of August 12, 2009, to the Credit Agreement, dated as of May 20, 2008, 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 August 14, 2009).
**12.1	Computation of Ratio of Earnings to Fixed Charges.
**21.1	List of Subsidiaries of Buckeye Partners, L.P.
**23.1	Consent of Deloitte & Touche LLP
**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.

* Represents management contract or compensatory plan or arrangement.

** Filed herewith.

(1) The Amended and Restated Agreements of Limited Partnership of the other Operating Partnerships are not filed because they are substantially identical to

Exhibit 10.1 except for the identity of Buckeye.

(2) The Management Agreements of the other Operating Partnerships are not filed because they are substantially identical to Exhibit 10.2 except for the identity of Buckeye.

(b) Exhibits

See Item 15(a)(3) above.

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SIGNATURES

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

Buckeye Partners, L.P.
(Registrant)

By: Buckeye GP LLC,
as General Partner

Dated: February 26, 2010

By: /s/ Forrest E. Wylie
Forrest E. Wylie
Chief Executive Officer
(Principal Executive Officer)

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

Dated: February 26, 2010	By: /s/ Irvin K. Culpepper Irvin K. Culpepper *Director*
Dated: February 26, 2010	By: /s/ John F. Erhard John F. Erhard *Director*
Dated: February 26, 2010	By: /s/ Michael B. Goldberg Michael B. Goldberg *Director*
Dated: February 26, 2010	By: /s/ C. Scott Hobbs C. Scott Hobbs *Director*
Dated: February 26, 2010	By: /s/ Mark C. McKinley Mark C. McKinley *Director*
Dated: February 26, 2010	By: /s/ Oliver G. Rick Richard, III Oliver Rick G. Richard, III *Director*

Dated: February 26, 2010	By: /s/ Keith E. St.Clair Keith E. St.Clair *Senior Vice President and Chief Financial Officer* *(Principal Financial Officer and Principal Accounting Officer)*
Dated: February 26, 2010	By: /s/ Robb E. Turner Robb E. Turner *Director*
Dated: February 26, 2010	By: /s/ Forrest E. Wylie Forrest E. Wylie *Director*

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