BUCKEYE PARTNERS, L.P.
Form 10-K
February 28, 2011

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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, 2010

OR

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

Commission file number 1-9356
Buckeye Partners, L.P.
(Exact name of registrant as specified in its charter)

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

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

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 ¨ 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 ¨

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 **þ** No ¨

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. ¨

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 ¨ No **þ**

At June 30, 2010, the aggregate market value of the registrant s limited partner units held by non-affiliates was $2.9 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 and Class B units outstanding as of February 22, 2011: 80,347,782 and 6,793,481, respectively.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s Proxy Statement being prepared for the solicitation of proxies in connection with the 2011 Annual Meeting of Limited Partners are incorporated by reference in Part III of this Form 10-K.

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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) changes in federal, state, local and foreign laws or regulations to which we are subject, including those that permit the treatment of us as a partnership for federal income tax purposes, (2) terrorism, adverse weather conditions, including hurricanes, environmental releases, and natural disasters, (3) changes in the marketplace for our products or services, such as increased competition, better energy efficiency, or general reductions in demand, (4) adverse regional, national or international economic conditions, adverse capital market conditions or adverse political development, (5) shutdowns or interruptions at the source points for the products we transport, store, or sell, (6) unanticipated capital expenditures in connection with the construction, repair, or replacement of our assets, (7) volatility in the price of refined petroleum products and the value of natural gas storage services, (8) nonpayment or nonperformance by our customers, (9) our ability to realize efficiencies expected to result from our previously announced reorganization, and (10) our ability to integrate acquired assets with our existing assets and to realize anticipated cost savings and other efficiencies. 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 partnership units representing limited partner interests (LP Units) are listed on the New York Stock Exchange (NYSE) under the ticker symbol BPL. Buckeye GP LLC (Buckeye GP) is our general partner and is a wholly owned subsidiary of Buckeye GP Holdings L.P. (BGH), a Delaware limited partnership that was previously publicly traded on the NYSE prior to Buckeye s merger with BGH (see below for further information). Unless the context requires otherwise, references to *we*, *us*, *our*, the *Partnership* or *Buckeye* intended to mean the business and operations of Buckeye Partners, L.P. and its consolidated subsidiaries.

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

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

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, 2010, Services Company owned approximately 2.1% of our LP Units. Services Company employees provide services to the operating subsidiaries through which we conduct our operations. Pursuant to a services agreement entered into in December 2004, our operating subsidiaries reimburse Services Company for the costs of the services it provides. 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, but, following completion of the Merger, BGH s obligation to make this payment was terminated. Services Company has been consolidated in our financial statements.

Our consolidated balance sheets include a noncontrolling capital account that relates primarily to Services Company and the portions of Sabina Pipeline (Sabina) and WesPac Pipelines Memphis LLC (WesPac Memphis) that are not owned by us. Similarly, our consolidated statements of operations include income attributable to noncontrolling interests that reflect the portion of the earnings due to Services Company and the owners of Sabina and WesPac Memphis. Prior to the Merger, noncontrolling interests reported by BGH also included portions of Buckeye owned by third-parties.

We own and operate one of the largest independent refined petroleum products pipeline systems in the United States in terms of volumes delivered, with approximately 5,400 miles of pipeline and 69 active products terminals that provide aggregate storage capacity of over 53 million barrels. In addition, we recently closed the acquisition of a Bahamian terminal facility with a total installed capacity of approximately 21.6 million barrels. We also operate and maintain approximately 2,600 miles of other pipelines under agreements with major oil and gas, petrochemical and chemical companies, and perform certain engineering and construction management services for third parties. We also own and operate a major natural gas storage facility in northern California, and are a wholesale distributor of refined petroleum products in the United States in areas also served by our pipelines and terminals.

We operate and report in five business segments: Pipeline Operations; Terminalling & Storage; Natural Gas Storage; Energy Services; and Development & Logistics. 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 2,700-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 350-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 1,250 miles located in Illinois, Indiana, Missouri and Ohio.

Buckeye Pipe Line Transportation LLC (BPL Transportation), which owns a refined petroleum products pipeline system with aggregate mileage of approximately 500 miles located in New Jersey, New York and Pennsylvania.

Everglades Pipe Line Company, L.P. (Everglades), which owns an approximately 40-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 active refined petroleum and other products terminals (of which 59 are included in our Terminalling & Storage segment and three are included in our Pipeline Operations segment) with aggregate storage capacity of approximately 26.3 million barrels and approximately 575 miles of pipelines in the Midwest and on the West Coast. BPH operates, through its subsidiaries, terminals and pipelines for third parties. BPH also holds noncontrolling stock interests in two Midwest refined petroleum products pipelines.

Buckeye Gas Storage LLC, which, through its subsidiary Lodi Gas Storage, L.L.C. (Lodi Gas), owns a natural gas storage facility in northern California that currently has approximately 29 Bcf of working natural gas storage capacity.

Buckeye Energy Holdings LLC, 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.

Buckeye Caribbean Holdings Limited, which, through its subsidiary, Buckeye Caribbean Terminals LLC, owns the terminal in Puerto Rico that we acquired in December 2010 (see 2010 Developments below for further information), with an aggregate storage capacity of approximately 4.6 million barrels, which is included in our Terminalling & Storage segment.

Buckeye Atlantic Holdings LLC, which, through its indirect subsidiary, Bahamas Oil Refining Company International Limited (BORCO), owns a terminal facility in Freeport, Grand Bahama, The

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Bahamas, with an aggregate storage capacity of approximately 21.6 million barrels, which is included in our Terminalling & Storage segment (see 2010 Developments below for further information).

The following chart depicts our ownership structure as of December 31, 2010 (ownership percentages in the chart are approximate).

* 99.5% Limited Partner Interest and 0.5% General Partner Interest

** MainLine Management LLC, as general partner of Buckeye GP Holdings L.P. has limited control rights. Buckeye GP LLC controls Buckeye, and all of Buckeye GP LLC s directors are elected by the LP unitholders.

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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:

- Maximize utilization of our assets at the lowest cost per unit;
- Maintain stable long-term customer relationships;
- Operate in a safe and environmentally responsible manner;
- Optimize, expand and diversify our portfolio of energy assets; and
- Maintain a solid, conservative financial position and our investment-grade credit rating.

We intend to achieve our strategy by:

- Acquiring, building and operating high quality, strategically located assets;
- Maintaining and enhancing the integrity of our pipelines, terminals and storage assets;
- Pursuing strategic cash flow-accretive acquisitions that:
  - Complement our existing footprint;
  - Provide geographic, product and/or asset class diversity; and
  - Leverage existing management capabilities and infrastructure; and
- Providing superior customer service.

2010 Developments

Merger

On November 19, 2010, we consummated the transactions contemplated by our Merger Agreement. Pursuant to the Merger Agreement, Merger Sub was merged into BGH, with BGH as the surviving entity. In the transaction, the incentive compensation agreement (also referred to as the incentive distribution rights) held by our general partner was cancelled, the general partner units held by our general partner (representing an approximate 0.5% general partner interest in us) were converted to a non-economic general partner interest, all of the economic interest in BGH was acquired by us and BGH unitholders received aggregate consideration of approximately 20.0 million of our LP Units. See Item 1, Introduction for further information.

We incurred $16.4 million of costs associated with the Merger during the year ended December 31, 2010. We charged these costs directly to partners capital.

Acquisition of BORCO

On December 18, 2010, we entered into a sale and purchase agreement with affiliates of FRC Founders Corporation (First Reserve), pursuant to which we agreed to acquire First Reserve s indirect 80% interest in FR Borco Coop Holdings, L.P. (FRBCH), the indirect owner of BORCO. On January 18, 2011, we completed the purchase of First Reserve s 80% interest in FRBCH for approximately $1.4 billion of cash and equity. On February 16, 2011, Vopak Bahamas B.V. (Vopak), which owned the remaining 20% interest in FRBCH, sold its interest to us at the same proportionate price and on the same terms and conditions as those in our agreement with First Reserve for approximately $340.0 million of cash and equity. In aggregate, we paid approximately $1.7 billion in a combination of cash and equity to acquire 100% of BORCO. BORCO is the fourth largest oil and petroleum products storage terminal in the world and the largest petroleum products facility in the Caribbean with current storage capacity of approximately 21.6 million barrels.

On January 13, 2011, we sold $650.0 million aggregate principal amount of 4.875% Notes due 2021 (the 4.875% Notes) in an underwritten public offering. The notes were issued at 99.62% of their principal amount. Total proceeds from this offering, after underwriters fees, expenses and debt issuance costs of $4.5 million, were approximately

$643.0 million, and were used to fund a portion of the purchase price for our acquisition of an indirect interest in FRBCH.

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On January 18 and 19, 2011, we issued 5,794,725 LP Units and 1,314,870 Class B Units to institutional investors for aggregate consideration of approximately $425.0 million to fund a portion of the BORCO acquisition. On January 18, 2011, we issued 2,483,444 LP Units and 4,382,889 Class B Units to First Reserve as $400.0 million of consideration to fund a portion of the acquisition of an indirect interest in FRBCH. On February 16, 2011, we issued 620,861 LP Units and 1,095,722 Class B Units to Vopak as $100.0 million of consideration to fund a portion of our acquisition of Vopak s 20% interest in BORCO. The remaining purchase price was funded with cash on hand at closing and borrowings under our unsecured revolving credit agreement (Credit Facility).

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

For additional information, see Terminalling & Storage Segment BORCO Acquisition below.

Amendment to BES Credit Agreement

On June 25, 2010, BES amended and restated its credit agreement (the BES Credit Agreement) to increase the total commitments for borrowings available to BES up to $500.0 million and extend the maturity date to June 25, 2013. However, the maximum amount available to be borrowed under the amended and restated BES Credit Agreement is initially limited to $350.0 million. An accordion feature provides BES the ability to increase the commitments under the BES Credit Agreement to $500.0 million, subject to obtaining the requisite lender commitments and satisfying other customary conditions. In addition to the accordion, subject to BES s satisfaction of certain financial covenants, BES may, from time to time, elect to increase or decrease the maximum amount available for borrowing under the BES Credit Agreement in $5.0 million increments, but in no event below $150.0 million or above $500.0 million. BES incurred $3.3 million of debt issuance costs related to the amendment, which is being amortized into interest expense over the term of the BES Credit Agreement. See Note 13 in the Notes to Consolidated Financial Statements for further information.

Purchase of Additional Interest in West Shore Pipe Line Company

On August 2, 2010, in connection with our exercise of a right of first refusal, we completed the acquisition of additional shares of West Shore Pipe Line Company (West Shore) common stock from an affiliate of BP plc, resulting in an increase in our ownership interest in West Shore from 24.9% to 34.6%. We paid approximately $13.5 million for this additional interest.

Sale of Buckeye NGL Pipeline

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

Terminal Acquisitions

On November 5, 2010, we acquired a refined petroleum products terminal in Opelousas, Louisiana from Chevron U.S.A. Inc. (Chevron) for $13.0 million in cash. The terminal, which is connected to the Colonial Pipeline, currently supplies central Louisiana with branded gasoline, diesel and ethanol. The terminal includes seven storage tanks with approximately 135,000 barrels of total storage capacity and a truck rack. Chevron entered into a commercial contract with us concurrent with the acquisition regarding usage of the acquired facility. See Note 4 in the Notes to Consolidated Financial Statements for further information.

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On December 10, 2010, we acquired a refined petroleum products terminal in Yabucoa, Puerto Rico from an affiliate of Royal Dutch Shell plc (Shell) for $32.6 million, net of cash acquired of $3.5 million. The terminal includes 44 storage tanks with approximately 4.6 million barrels of gasoline, jet fuel, diesel, fuel oil and crude oil storage capacity. Shell entered into a commercial contract with us concurrent with the acquisition regarding usage of the acquired facility. See Note 4 in the Notes to Consolidated Financial Statements for further information.

Business Activities

The following discussion describes the business activities of our business segments, which include Pipeline Operations, Terminalling & Storage, Natural Gas Storage, Energy Services and Development & 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, except for one terminal located in Puerto Rico and one terminal located in The Bahamas. 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,					
	2010		2009		2008	
	Revenue	Percent	Revenue	Percent	Revenue	Percent
Pipeline Operations	$ 400,926	12.7%	$ 392,667	22.3%	$ 387,267	20.4%
Terminalling & Storage	175,000	5.6%	136,576	7.7%	119,155	6.3%
Natural Gas Storage	95,337	3.0%	99,163	5.6%	61,791	3.3%
Energy Services	2,481,566	78.7%	1,125,013	63.5%	1,295,925	68.3%
Development & Logistics	37,696	1.2%	34,136	1.9%	43,498	2.3%
Intersegment	(39,257)	-1.2%	(17,183)	-1.0%	(10,984)	-0.6%
Total	$ 3,151,268	100.0%	$ 1,770,372	100.0%	$ 1,896,652	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,					
	2010		2009		2008	
	Volume	Percent	Volume	Percent	Volume	Percent
Gasoline	643.7	49.3%	650.1	49.6%	673.5	48.7%
Jet fuel	338.5	26.0%	336.7	25.7%	354.7	25.7%
Middle distillates (1)	301.3	23.1%	284.7	21.7%	304.2	22.0%
NGLs (2)		0.0%	13.9	1.1%	20.9	1.5%
Other products	21.0	1.6%	24.5	1.9%	28.9	2.1%
Total (3)	1,304.5	100.0%	1,309.9	100.0%	1,382.2	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.

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 925 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 350-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 approximately 2,100 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 1,250 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 terminal located on the Ohio River in Mt. Vernon, Indiana.

Other Refined Petroleum Products Pipelines

Buckeye Pipe Line serves Connecticut and Massachusetts through an approximately 100-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 40-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-mile pipeline serving the Reno/Tahoe International Airport. WesPac Pipelines San Diego LLC (WesPac San Diego) owns an approximately 4-mile pipeline serving the San Diego International Airport. WesPac Memphis owns an approximately 15-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, 2010, we had provided $41.4 million in intercompany financing to WesPac Memphis. Each of these entities has been consolidated into our financial statements.

Equity Investments

BPH owns a 34.6% equity interest in West Shore. In August 2010, in connection with our exercise of a right of first refusal, we completed the acquisition of additional shares of West Shore common stock from an affiliate of BP plc, resulting in an increase in our ownership interest in West Shore from 24.9% to 34.6%. See 2010 Recent Developments above for further information. West Shore owns an approximately 650-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 affiliated with major oil companies. Since January 1, 2009, we have operated 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 2,300-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 Pipeline LLC 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.

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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 & Storage Segment

The Terminalling & Storage segment includes 61 terminals (including the BORCO terminal discussed below) that provide bulk storage and throughput services with respect to refined petroleum products and renewable fuels, including ethanol, and has an aggregate storage capacity of approximately 52.0 million barrels. Of our 61 terminals in the Terminalling & Storage segment, 45 are connected to our pipelines and 16 are not. We generally own the property on which the terminals are located with the exception of our terminals located in Albany, New York, Yabucoa, Puerto Rico and The Grand Bahama Island, each of which is primarily located on leased property. See BORCO Acquisition below for a discussion of the BORCO terminal acquired in 2011.

The Terminalling & Storage segment s terminals receive products from pipelines and, in certain cases, barges, ships or 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 & 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 Terminalling & Storage 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, ships or pipelines. In addition to these throughput fees, revenues are generated by charging customers fees for blending with renewable fuels, injecting additives and leasing storage 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 & Storage segment s products terminals for the periods indicated (volume in average barrels per day):

	Year Ended December 31,		
	2010	**2009**	**2008**
Products throughput (1)	564,300	471,900	464,400

(1) Reported quantities include volumes from our terminal located in Albany, New York. For the years ended December 31, 2009 and 2008, we previously reported total products throughput of 444.9 thousand and 457.4 thousand barrels, respectively, which excluded volumes from the Albany, New York terminal.

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The following table sets forth the number of terminals and storage capacity in barrels by location for terminals reported in the Terminalling & Storage segment:

Location	Number of Terminals (1)	Storage Capacity (000s Barrels)
Bahamas (2)	1	21,612
Connecticut	1	345
Illinois	9	3,161
Indiana	10	8,910
Louisiana	1	135
Massachusetts	1	106
Michigan	10	3,908
Missouri	2	345
New York	10	4,111
Ohio	8	2,871
Pennsylvania	4	1,131
Puerto Rico	1	4,623
Wisconsin	3	734
Total	61	51,992

(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, which are included in the Energy Services segment for reporting purposes (as discussed below), in Pennsylvania with aggregate storage capacity of approximately 0.5 million barrels.

(2) In 2011, we acquired a Bahamian terminal facility with a total installed capacity of approximately 21.6 million barrels. See BORCO Acquisition below.

BORCO Acquisition

In January 2011, we acquired an indirect 80% interest in BORCO from First Reserve and in February 2011, we acquired the remaining 20% interest from Vopak (see 2010 Developments). BORCO owns a terminal facility located along the Northwest Providence Channel of The Grand Bahama Island, which it uses to operate a fully integrated terminalling business and offers customers storage, berthing, heating, transshipment, blending, treating, bunkering and other ancillary services. This acquisition and the Yabucoa, Puerto Rico terminal acquisition represent our entry into the marine terminals business.

BORCO s terminal facility includes 80 aboveground storage tanks ranging in capacity from 5,000 to 500,000 barrels with a total installed capacity of approximately 21.6 million barrels. Presently 66 of the 80 tanks are available to serve third parties, as 14 of the tanks (representing only 0.2 million barrels) are dedicated for BORCO s own use. Of the 66 tanks available to serve third parties, 10 are currently used for the storage of crude oil, 43 for the storage of fuel oil and 13 for the storage of clean petroleum products, such as gasoline, diesel and certain other distillates. Six of the tanks currently used for crude oil can be converted between crude oil service and fuel oil service. In response to customer demand, BORCO is prepared to undertake a significant expansion project, which we expect will be phased in over the next two to three years. BORCO continues to discuss with its existing customers and potential new customers their storage and service requirements as we refine our expansion plans. New tankage is expected to be constructed with the flexibility to store fuel oil, clean petroleum products or crude oil. We expect an expansion plan, which phases in capacity additions, to be finalized in the near future. In addition, the facility site also has additional unused land available for future expansions, with room to more than double the existing storage capacity if all the expansion opportunities are utilized.

The existing marine infrastructure of BORCO s terminal facility consists of three deep-water jetties. The jetties are situated in water depths ranging from approximately 42 feet to 100 feet and are approximately 3,000 feet to

4,000 feet from shoreline. After completion of an ongoing refurbishment project on one of the jetties, which is expected to occur in the second half of 2011, the three jetties will provide six deep-water berths that serve as the access points to the storage facilities and are capable of handling vessels over a range of deadweight tonnage (DWT), from a minimum of 20,000 DWT to a maximum of 500,000 DWT, including both very large crude carriers and ultra large crude carriers.

BORCO s terminal facility also includes an inland dock with an approximately 650-foot berth located in Freeport Harbor. BORCO currently leases the inland dock from the Freeport Harbour Company under a long-term agreement through 2067. The inland dock is in the process of being upgraded, which will include the build-out of a new berth. Upon completion, the inland dock will include two berths capable of handling Panamax vessels of up to 80,000 DWT. We expect completion of the upgrade of the inland dock to occur in 2011. Upon completion of the jetty refurbishment and inland dock renovation projects, BORCO will have a total of eight berths.

Ancillary services provided by BORCO facilitate customer activities within the tank farm and at the jetties. Onshore activities include heating, blending, and treating of petroleum products. BORCO offers complete berthing services to vessels loading and unloading at the facility, including piloting, vessel mooring (line handling), tug services and tendering services.

BORCO employs a non-union workforce that currently consists of approximately 230 full-time employees and part-time contractors.

Vopak historically managed certain aspects of BORCO s business pursuant to an operating agreement that was terminated upon closing of the purchase of Vopak s interest in BORCO on February 16, 2011. Operatorship of BORCO s business was transferred to us in connection with the closing and, pursuant to a transition support agreement, during a transition period of up to 180 days following closing, Vopak will provide certain transition support services with respect to information technology systems, accounting, project management, insurance and regulatory reporting.

Natural Gas Storage Segment

The Natural Gas Storage segment provides natural gas storage services through a facility located in northern California. Currently, the facility currently has approximately 29 Bcf of working natural gas storage capacity 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 facility is located approximately 30 miles south of Sacramento, near Lodi, California, and has been in service since January 2002. The Kirby Hills facility is located approximately 30 miles west of Lodi in the Montezuma Hills, nine miles southeast of Fairfield, California. The Natural Gas Storage segment s three storage facilities have daily maximum injection and withdrawal capability of 550 MMcf/day and 750 MMcf/day, respectively, utilizing over thirty wells. Thirty-one miles of pipeline links the original Lodi Gas facility to an interconnect with Pacific Gas and Electric just north of Antioch, California. Six miles of pipeline links the Kirby Hills facility to an interconnect with Pacific Gas and Electric approximately six miles west of Rio Vista, California.

The Natural Gas Storage segment is regulated by the California Public Utilities Commission (CPUC). All services have been, and will continue to be, contracted under the Natural Gas Storage segment s published CPUC tariff.

The Natural Gas Storage segment s revenues primarily 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

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 allows us to increase the utilization of our existing pipeline and terminal assets by marketing refined petroleum products in areas served by those assets. The segment markets 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,		
	2010	**2009**	**2008**
Sales volumes	1,139,100	655,100	435,200

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 truck loading equipment at storage facilities.

Wholesale Delivered liquid fuels are delivered, through third-party carriers, 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 expose 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 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 physical fixed-priced contracts. However, hedge accounting has not been elected for all of the Energy Services segment s derivative instruments. Fixed-price purchase and sales contracts are generally hedged with financial instruments; however, these instruments are not designated in a hedge relationship. In the cases in which hedge accounting has not been used for physical derivative contracts, changes in the fair values of the financial instruments, which are included in cost of product sales, generally are offset by changes in the values of the physical derivative contracts which are also derivative instruments whose changes in value are recognized in product sales or cost of product sales. In addition, hedge accounting has not been elected for financial instruments that have been executed to economically hedge a portion of the Energy Services segment s refined petroleum products held in inventory. The changes in value of the financial instruments that are economically hedging inventory are recognized in cost of product sales.

Development & Logistics Segment

The Development & Logistics segment consists primarily of terminal and pipeline operations and maintenance services and related construction services for third parties. The Development & 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, 2010, our Development & Logistics segment had performance obligations under existing multi-year arrangements to operate and maintain approximately 2,600 miles of pipeline. Further, this segment owns an approximately 25-mile pipeline located in Texas and leases a portion of

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the pipeline to a third-party chemical company. The Development & Logistics segment also owns an approximate 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 & Logistics segment provides engineering and construction management services and asset development services to energy companies in the United States and internationally.

Third-party contract operation and maintenance services will continue to be a key area of focus for this segment. In addition to its operation and maintenance services, the Development & Logistics segment operates as an asset and business development arm for many of its third-party asset owners as well as for other oil and gas, petrochemical and chemical companies. The Development & Logistics segment will continue to use its core capabilities of project development, idea origination, commercial management and operational competency to expand outside of its existing service area of pipeline and terminal assets into opportunities which are positioned off of our existing systems.

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 believe the Merger lowered our cost of equity capital and thereby enables us to compete for more accretive acquisitions.

Pipeline Operations and Terminalling & 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 Cincinnati, Ohio and locations on the Mississippi River, such as St. Louis, Missouri.

Our facility in Yabucoa, Puerto Rico faces significant competition for motor fuel and residual fuel oil distribution from other independent third party terminal locations similarly situated in proximity of certain demand centers. The Yabucoa facility is not directly connected by pipeline to any of the regional airports or local power generation plants thereby increasing customer handling costs to supply these products by other modes of transportation. Our facility in Freeport, Bahamas competes with other proprietary and third party independent terminal operators in the Caribbean region. Utilization of this facility is highly dependent on the storage, blending and export of products by our customers to other locations within the Caribbean, North and South America, Europe and Asia. Internal transfer pricing of certain regional facilities and discounted incentive storage and handling rates at independent third party facilities supported by quasi national oil companies increases the competition for handling of remaining product demand.

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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 through our pipeline, and additional blending opportunities within our Terminalling & 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 & Storage segment. The Terminalling & 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 & Storage segment s terminals. While the Terminalling & 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 trading platforms, 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.

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Development & Logistics Segment

The Development & 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 some instances it can be either more cost-effective or strategic for certain companies to operate and maintain their own pipelines as opposed to contracting with the Development & Logistics segment to complete these tasks. Numerous engineering and construction firms compete with the Development & Logistics segment for construction management business.

Customers

For the years ended December 31, 2010, 2009 and 2008, no customer contributed more than 10% of our consolidated revenue.

Seasonality

The Pipeline Operations and Terminalling & 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.

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 Services Company. At December 31, 2010, Services Company had approximately 859 full-time employees, 155 of whom were represented by two labor unions. At December 31, 2010, approximately 22 people were employed directly by Lodi Gas, 17 people were employed directly by a subsidiary of BPH and 20 people were directly employed by Buckeye Caribbean Terminals LLC. 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 2010, we spent approximately $77.7 million for capital expenditures, of which $31.2 million related to sustaining capital projects and $46.5 million related to expansion and cost reduction projects.

Excluding capital expenditures related to the BORCO facility, we expect to spend approximately $110.0 million to $130.0 million for capital expenditures in 2011, of which approximately $30.0 million to $40.0 million is expected to relate to sustaining capital expenditures and $80.0 million to $90.0 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 2011 will include completion of

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additional storage tanks in the Midwest, the refurbishment of storage and facilities in the Northeast, vapor recovery units throughout our system of terminals and various upgrades and expansions of our ethanol business. Cost reduction expenditures improve operational efficiencies or reduce costs.

We expect to spend approximately $200.0 million to $250.0 million for capital expenditures in 2011 related to the BORCO facility, of which $185.0 million to $225.0 million is expected to relate to expansion projects and $15.0 million to $25.0 million is expected to relate to sustaining capital expenditures. Major expansion expenditures in 2011 is expected to include upgrades and expansions of the jetty structure, the inland dock and berth developments and terminal storage tank expansion 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 and state corporation 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, the Energy Policy Act of 1992 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 (as of 2010 the change in the Producer Price Index finished goods (PPI-FG) plus 1.3%) that FERC believes reflects cost changes appropriate for application to pipeline rates although in December 2010, FERC amended its regulations to change the index to the PPI-FG plus 2.65% effective July 1, 2011. 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 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 the index 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. Shippers may file protests against the application of the index to the rates of an individual pipeline and 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 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.

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 Item 3, Legal Proceedings. The following is a summary of the more significant current environmental laws and regulations to which our business operations are subject and for which compliance may require material capital expenditure or have a material adverse impact on our results of operations or financial position.

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, special wastes or regulated solid waste. 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. Although CERCLA contains a petroleum exclusion , that provision generally applies only to unused product not contaminated by contact with other substances, and may exclude product recovered after a release, as well as contact or sting water. 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. EPA has recently begun promulgating greenhouse gas (GHG) regulations and otherwise increasing its scrutiny of the oil and gas industry. It is possible that new or more stringent controls will be imposed on us through these programs.

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 Pipeline Safety Act (PSA). In promulgating the PSA in 1994, Congress combined and re-codified, without substantial modification, the provisions of the two existing pipeline safety statutes: the Natural Gas Pipeline Safety Act of 1968 (NGPSA) and the Hazardous Liquid Pipeline Safety Act of 1979. The PSA governs the design, installation, testing, construction, operation, replacement and management of pipeline facilities. PSA 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 current PSA is up for reauthorization in 2011, and the industry anticipates that new statutory and regulatory obligations on the industry will be established through that process. In particular, PHMSA is expected to promulgate new regulations applicable to our pipeline operations.

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.

PSA 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, by pressure testing or other specific and approved technologies. 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 PSA, 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 NGPSA as subsequently amended, which required the Secretary of Transportation to implement regulations imposing safety, programs such as integrity management, operator qualification and public education and also other reporting obligations.

We believe that we currently comply in all material respects with PSA, 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.

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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 any future 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.

Available Information

We file annual, quarterly and current reports and other documents with the SEC under the Securities Exchange Act of 1934. 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 Securities Exchange Act of 1934 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 investments in us. 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 investments in us 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 the products we handle in the regions we serve and the supply of products in the regions connected to our pipelines or from which our customers source products handled by our terminals. Prevailing economic conditions, refined petroleum product, fuel oil and crude oil 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, changes in global patterns of supply and demand for fuel oil, crude oil and clean petroleum products could affect the demand for the services we provide at BORCO.

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, the most significant competitors for large volume shipments in our Pipeline Operations segment 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.

Our 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 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 for our Pipeline Operations segment. 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.

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.

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.

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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 our 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. Approval from the Central Bank of the Bahamas will be required before BORCO can make distributions to us. 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 unknown and contingent 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.

The BORCO facility was constructed between 1968 and 1975 and was initially constructed and designed to operate as a refinery which was permanently shut down in 1985. We have performed a certain level of diligence in connection with the acquisition of BORCO and have attempted to verify the representations made by First Reserve and Vopak, but there may be unknown and contingent liabilities related to BORCO of which we are unaware. First Reserve and Vopak have not agreed to indemnify us for losses or claims relating to the operation of the business or otherwise except for breaches of First Reserve s and Vopak s obligations to pay certain fees, transfer taxes and expenses and for certain breaches of representations and warranties of First Reserve and Vopak.

If a significant release or event occurred in the past at any of our acquired assets, including BORCO, 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. We could be liable for unknown obligations relating to any of our acquired assets, for which indemnification is not available, which could materially adversely affect our business, results of operations and cash flow.

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.

A substantial amount of the petroleum products handled by BORCO are exported from Venezuela, which exposes us to political risks.

A substantial portion of BORCO s revenues relate to petroleum products exported from Venezuela by Petróleos de Venezuela, S.A. (commonly referred to as PDVSA). This involvement with products exported from Venezuela exposes BORCO to significant risks, including potential political and economic instability and trade restrictions and economic embargoes imposed by the United States and other countries.

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.

The representations, warranties, and indemnifications made by each of First Reserve and Vopak are limited in the BORCO sale and purchase agreements and our diligence of BORCO has been limited; as a result, the assumptions on which our estimates of future results of BORCO have been based may prove to be incorrect in a number of material ways, resulting in us not realizing the expected benefits of the BORCO acquisition.

The representations and warranties made by each of First Reserve and Vopak are limited in the BORCO sale and purchase agreements and our diligence of BORCO has been limited. In addition, the sale and purchase agreements do not provide any indemnities other than for breaches of First Reserve s and Vopak s obligations to pay certain fees, transfer taxes and expenses and for certain breaches of representations and warranties of First Reserve and Vopak. As a result, the assumptions on which our estimates of future results of BORCO have been based may prove to be incorrect in a number of material ways, resulting in us not realizing our expected benefits of the BORCO acquisition, including anticipated increased cash flow.

We are in the process of refining our expansion plans for BORCO. Once those plans are finalized, we may not be able to execute those expansion plans on economically viable terms, if at all. In connection with this expansion effort, we may encounter difficulties. These risks include the following:

- unexpected operational events;
- adverse weather conditions;
- inadequate customer demand for, or interest in, flexible storage;
- regulatory hurdles;
- facility or equipment malfunctions or breakdowns;
- a shortage of skilled labor; and
- risks associated with subcontractors services, supplies, cost escalation and personnel.

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, the Energy Policy Act of 1992 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.

The indexing methodology is used to establish rates on the pipelines owned by Wood River, BPL Transportation and NORCO. The indexing method in 2010 allowed a pipeline to increase its rates by a percentage equal to the change in the PPI-FG plus 1.3% although in December 2010, FERC amended its regulations to change the index to the PPI-FG plus 2.65% effective July 1, 2011. If the index were to be negative, we would be required to reduce the rates charged by Wood River, BPL Transportation and NORCO if they exceed the new maximum allowable rate. 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 protests against the application of the index to an individual pipeline s rates, as well as 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). 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. Furthermore, the EPA has issued a final rule setting emission standards for light-duty vehicles for the 2012-2016 model years. In October 2010, the EPA announced its intent to implement a GHG emissions reducing program for medium- and heavy-duty vehicles. Motor vehicle emission standards could impact our operations by effectively reducing demand for motor fuels from crude oil. Furthermore, the EPA has asserted that final motor vehicle GHG emission standards will trigger construction and operating permit requirements for stationary sources, although the EPA has proposed to tailor such that only large stationary sources will be required to obtain air permits for new or modified facilities. Thus, adoption of the motor vehicle standards could also potentially affect our operations and ability to obtain air permits for new or modified facilities.

Legislation and regulations relating to control or reporting of GHG emissions are also in various stages of discussions or implementation in many of the states in which we operate. The adoption and implementation of any legislation or 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.

In addition to potential impacts on our business directly or indirectly resulting from climate-change legislation or regulations, our business also could be negatively affected by climate-change related physical changes or changes in weather patterns. An increase in severe weather patterns could result in damages to or loss of our physical assets, impact our ability to conduct operations and/or result in a disruption of our customer s operations. These climate-change related physical changes could also affect entities that provide goods and services to us and indirectly have an adverse affect on our business as a result of increases in costs or availability of goods and services. Changes of this nature could have a material adverse impact on our business.

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.

BORCO may be adversely affected by economic, political and regulatory developments.

BORCO s terminal facility is located in The Bahamas. As a result, we are exposed to the risks of international operations, including political, economic and regulatory developments and changes in laws or policies affecting our terminal operations, as well as changes in the policies of the United States affecting trade, taxation and investment in other countries. Any such developments or changes could have a material adverse effect on our business, results of operations and cash flow.

Compliance with laws and regulations that apply to BORCO increases the cost of doing business and could interfere with our ability to offer services or expose us to fines and penalties. These numerous laws and regulations include the Foreign Corrupt Practices Act and local laws prohibiting corrupt payments to government officials or agents. Although policies designed to fully ensure compliance with these laws are in place or under development, employees, contractors, or agents may violate the policies. Any such violations could include prohibitions on BORCO s ability to offer its services and could have a material adverse effect on our business, financial results and cash flow.

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. Congress will reauthorize the Pipeline Safety Act in 2011, and PHMSA is expected to promulgate new regulations. These actions may affect our operations.

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

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 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 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 contract. We are, however, required to make the settlement payment under the futures contract even if a fixed-price contract customer does not perform. Nonperformance under fixed-price contracts by a significant number of our customers could have an adverse effect on our business, financial condition, results of operations or cash flows.

BORCO depends on a limited number of customers for substantially all of its revenue, and the loss of any of them could adversely affect our results of operations and cash flow.

Storage revenue represented approximately 80% of BORCO s total revenue for the nine months ended September 30, 2010. Currently, BORCO has a limited number of long-term storage customers, consisting of oil majors, energy companies, physical traders and one national oil company. For the nine months ended September 30, 2010, approximately 30% and 69% of storage revenue was derived from the top one and the top three customers, respectively. We expect BORCO to continue to derive substantially all of its total revenue from a small number of customers in the future. BORCO may be unsuccessful in renewing its storage contracts with its customers, and those customers may discontinue or reduce contracted storage from BORCO. If any of BORCO s customers, in particular its top three customers, significantly reduces its contracted storage with BORCO and if BORCO is unable to find other storage customers on terms substantially similar to the terms under BORCO s existing storage contracts, our business, results of operations and cash flow could be adversely affected.

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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. The Department of Homeland Security began additional scrutiny and enforcement of the CFATS requirements in 2010, and that is expected to continue. 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.

Hurricanes could damage the facilities or disrupt our marine terminals or the operations of their customers, which could have a material adverse effect on our business, financial results and cash flow.

The operations of BORCO or our Yabucoa, Puerto Rico facility could be impacted by severe weather conditions such as hurricanes. Any such event could cause a serious business disruption or serious damage to such facilities, which could affect such facilities ability to provide terminalling services. Additionally, such events could impact our marine terminal facilities customers, and they may be unable to utilize our services. Any such occurrence could have a material adverse effect on our business, financial results and cash flow.

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.

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.

Financing the BORCO acquisition substantially increased our leverage.

In January 2011, we sold $650.0 million aggregate principal amount of 4.875% Notes due 2021. The increase in our indebtedness may reduce our flexibility to respond to changing business and economic conditions or to fund capital expenditures or working capital needs.

Risks Relating to Partnership Structure

We may sell additional units, diluting existing interests of Unitholders.

Our partnership agreement allows us to issue additional units and certain other equity securities without Unitholder approval. There is no limit on the total number of units and other equity securities we may issue. When we issue additional 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 units. Issuance of additional units will also diminish the relative voting strength of the previously outstanding LP Units.

Our partnership agreement limits the liability of our general partner and its directors and officers.

Our general partner and its directors and officers owe 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 and its directors and officers 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.

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

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 Internal Revenue Service (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, a publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless its gross income from its business activities satisfies a qualifying income requirement. Qualifying income includes income and gains derived from the transportation, storage, processing and marketing of natural resources, including crude oil, natural gas and products thereof. Based upon our current operations we believe that we are treated as a partnership rather than a corporation for such purposes; however, a change in our business could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

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In addition, 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, Congress has recently considered legislation that would have eliminated partnership tax treatment for certain publicly traded partnerships. Although such legislation would not have applied to us as proposed, it could be reintroduced or 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 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.

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 result 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 you realize 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 depreciation recapture. In addition, because your amount realized includes your 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. Recently, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration 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.

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.

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 technically 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 relief program whereby, a publicly traded partnership that technically terminates may be allowed 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, a Unitholder 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, a Unitholder 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 a Unitholder does not live in any of those jurisdictions. A Unitholder 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, a Unitholder may be subject to penalties for failure to comply 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. Additionally, we also own property and conduct business in Puerto Rico and The Grand Bahamas. Under current law, you are not required to file a tax return or pay taxes in either of these jurisdictions. 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 a Unitholder s 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.

BORCO is currently exempt from Bahamian taxation. If BORCO s tax status in The Bahamas were to change, such that BORCO has more tax liability than we anticipate, our cash flow could be materially adversely affected.

BORCO is currently exempt from income and property tax in The Bahamas pursuant to concessions granted under the Hawksbill Creek Agreement between the Government of the Bahamas and the Grand Bahama Port Authority. BORCO s exemption from Bahamian taxation pursuant to the Hawksbill Creek Agreement is scheduled to expire in 2015. If the Bahamian governmental authorities do not extend the concessions under the Hawksbill Creek Agreement or BORCO s tax status in The Bahamas were to otherwise change, such that BORCO has more tax liability than we anticipate, our cash flow could be materially adversely affected.

Item 1B. *Unresolved Staff Comments*

None.

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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. BORCO currently leases the inland dock under a long-term agreement through 2067.

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.

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.

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

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

In January 2011, PHMSA issued us a final order with penalties totaling $0.2 million in connection with issues related to documentation, inspection and physical signage of certain of our pipelines raised as a result of PHMSA s 2005 2006 inspection of certain facilities in Illinois, Indiana, Ohio, and Michigan as well as compliance records.

In January 2011, PHMSA issued us a final order with penalties totaling $0.1 million in connection with an employee s failure to follow certain pipeline-marking procedures in connection with a product release that occurred in New York, New York in November 2009.

On July 30, 2010, a putative class action was filed by a unitholder against BGH, MainLine Management LLC (MainLine Management), BGH GP Holdings, LLC (BGH GP) and each of MainLine Management s directors in the District Court of Harris County, Texas under the caption *Broadbased Equities v. Forrest E. Wylie, et. al.* In the Petition, the plaintiff alleged that MainLine Management and its directors breached their fiduciary duties to BGH s public unitholders by, among other things, acting to facilitate the sale of BGH to Buckeye in order to facilitate the gradual sale by BGH GP of its interest in BGH and failing to disclose all material facts in order that the BGH unitholders can cast an informed vote on the Merger Agreement. Among other things, the Petition sought an order certifying a class consisting of all BGH unitholders, a determination that the action is a proper derivative action, damages in an unspecified amount, and an award of attorneys fees and costs.

On August 2, 2010, a putative class action was filed by a unitholder against BGH, MainLine Management, Merger Sub, Buckeye, Buckeye GP and each of MainLine Management s directors in the District Court of Harris County, Texas under the caption *Henry James Steward v. Forrest E. Wylie, et. al.* In the Petition, the plaintiff alleged that MainLine Management and its directors breached their fiduciary duties to BGH s public unitholders by, among other things, failing to disclose all material facts in order that the BGH unitholders can cast an informed vote on the Merger Agreement. The Petition also alleged that Buckeye, Buckeye GP and Merger Sub aided and abetted the breaches of fiduciary duty. Among other things, the Petition sought an order certifying a plaintiff class consisting of all of BGH unitholders, an order enjoining the Merger, rescission of the Merger, damages in an unspecified amount, and an award of attorneys fees and costs.

On August 2, 2010, a putative class action was filed by a unitholder against BGH, MainLine Management, BGH GP, ArcLight Capital Partners (ArcLight), Kelso & Company (Kelso), Buckeye, Buckeye GP and each of MainLine Management s directors, in the District Court of Harris County, Texas under the caption *JR Garrett Trust v. Buckeye GP Holdings L.P. et al.* In the Petition, the plaintiff alleged that MainLine Management and its directors breached their fiduciary duties to BGH s public unitholders by, among other things, accepting insufficient consideration, failing to condition the Merger on a majority vote of public unitholders of BGH, and failing to disclose all material facts in order that the BGH unitholders can cast an informed vote on the Merger Agreement. The Petition also alleged that Buckeye, Buckeye GP, BGH GP, ArcLight and Kelso aided and abetted the breaches of fiduciary duty. Among other things, the Petition sought an order certifying a class consisting of all of BGH s unitholders, an order enjoining the Merger, damages in an unspecified amount, and an award of attorneys fees and costs.

On August 24, 2010, the District Court of Harris County, Texas, entered an order consolidating three previously filed putative class actions (*Broadbased Equities v. Forrest E. Wylie, et. al.*, *Henry James Steward v. Forrest E. Wylie, et. al.*, and *JR Garrett Trust v. Buckeye GP Holdings L.P., et al.,*) under the caption of *Broadbased Equities v. Forrest E. Wylie, et al.* and appointing interim co-lead class counsel and interim co-liaison counsel. The plaintiffs subsequently filed a consolidated amended class action and derivative complaint on September 1, 2010 (the Complaint). The Complaint purports to be a putative class and derivative action alleging that MainLine Management LLC (MainLine Management) and its directors breached their fiduciary duties to BGH s public unitholders in connection with the Merger by, among other things, accepting insufficient consideration and failing to disclose all material facts in order that BGH s unitholders may cast an informed vote on the Merger Agreement, and that we, Buckeye GP, MainLine Management, Merger Sub, BGH GP, ArcLight and Kelso aided and abetted the breaches of fiduciary duty.

On October 29, 2010, the parties to the litigation entered into a Memorandum of Understanding (MOU) in connection with a proposed settlement of the class action and the Complaint. The MOU provides for dismissal with prejudice of the litigation and a release of the defendants from all present and future claims asserted in the litigation in exchange for, among other things, the agreement of the defendants to amend the Merger Agreement to reduce the termination fees payable by BGH upon termination of the Merger Agreement and to provide BGH s unitholders with supplemental disclosure to BGH s and our joint proxy statement/prospectus, dated September 24, 2010. The supplemental disclosure is set forth in a joint proxy statement/prospectus supplement, dated October 29, 2010, which was filed with the SEC on November 1, 2010.

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In addition, the MOU provides that, in settlement of the plaintiffs claims (including any claim against the defendants by the plaintiffs counsel for attorneys fees or expenses related to the litigation), the defendants (or their insurers) will pay a cash payment of $900,000, subject to final court approval of the settlement. On January 25, 2011, pursuant to the MOU, the parties signed a Stipulation of Settlement. The Stipulation of Settlement has not yet been filed with the court. The proposed settlement is subject to several conditions, including, without limitation, court approval. There is no assurance that the court will approve the settlement.

We and the other defendants vigorously deny all liability with respect to the facts and claims alleged in the Complaint, and specifically deny that any modifications to the Merger Agreement or any supplemental disclosure was required or advisable under any applicable rule, statute, regulation or law. However, to avoid the substantial burden, expense, risk, inconvenience and distraction of continuing the litigation, and to fully and finally resolve the claims alleged, we and the other defendants agreed to the proposed settlement described above.

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, 2010 and 2009, as reported in the NYSE Composite Transactions, were as follows:

	2010		2009	
Quarter	**High**	**Low**	**High**	**Low**
First	$61.50	$51.68	$43.25	$32.00
Second	62.39	45.00	43.69	35.01
Third	66.00	57.19	49.44	41.43
Fourth	71.67	62.00	57.00	47.51

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 104,997 at December 31, 2010.

Cash distributions paid to Unitholders for the years ended December 31, 2010 and 2009 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 16, 2010	February 26, 2010	$ 0.9375
May 17, 2010	May 28, 2010	0.9500
August 16, 2010	August 31, 2010	0.9625
November 15, 2010	November 30, 2010	0.9750

On February 11, 2011, we announced a quarterly distribution of $0.9875 per LP Unit that is payable on February 28, 2011, to Unitholders of record on February 21, 2011. Total cash distributed to Unitholders on February 28, 2011 will be approximately $79.3 million. Class B unitholders will not receive a distribution of cash,

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but instead, we have elected to issue additional Class B Units in lieu of a cash distribution as permitted under the terms of the Class B Units.

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.

Issuer Purchases of Equity Securities

On November 19, 2010, we consummated the Merger with our general partner, BGH, BGH s general partner and Merger Sub. At the closing of the transactions under the Merger Agreement, we acquired all of the equity interest in BGH. BGH owned 80,000 of our LP Units, which were cancelled upon our acquisition of BGH pursuant to the terms of our partnership agreement.

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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 was 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). The financial statements of Services Company, which employs the employees who manage and operate us, are also consolidated into our financial statements.

The financial information for the periods prior to the effective date of the Merger was originally that of BGH. Although Buckeye is the surviving entity for legal purposes, BGH is the surviving entity for accounting purposes; therefore, all of the historical data included in this Item 6 prior to the Merger is BGH s. Because BGH controlled Buckeye prior to the Merger, Buckeye s financial statements were consolidated into BGH prior to the Merger. For accounting purposes, the Merger resulted in a reverse unit split, and the historical per unit amounts presented in this Item 6 have been retrospectively restated accordingly.

	Year Ended December 31,				
	2010	**2009**	**2008**	**2007**	**2006**
Income Statement Data:					
Revenue (1)	$3,151,268	$1,770,372	$1,896,652	$ 519,347	$ 461,760
Depreciation and amortization	59,590	54,699	50,834	40,236	39,629
Equity plan modification expense (2)	21,058				
Asset impairment expense (2)		59,724			
Reorganization expense (2)		32,057			
Operating income (1) (2)	279,501	203,800	246,492	195,353	164,873
Interest and debt expense	89,169	75,147	75,410	51,721	60,702
Net income (2)	201,008	141,637	180,623	152,675	111,800
Net income attributable to noncontrolling interests (3)	(157,928)	(92,043)	(154,146)	(129,754)	(103,066)
Net income attributable to Buckeye Partners, L.P. (1)	43,080	49,594	26,477	22,921	8,734
Net income from August 9 to December 31, 2006					2,599
Earnings per LP Unit diluted (4)	$ 1.65	$ 2.49	$ 1.33	$ 1.15	$ 0.13
Distributions per LP Unit (5)	$ 3.83	$ 3.63	$ 3.43	$ 3.23	$ 3.03

	December 31,				
	2010	**2009**	**2008**	**2007**	**2006**
Balance Sheet Data:					
Total assets (1)	$3,574,216	$3,486,571	$3,263,097	$2,354,326	$2,212,585
Total debt, including current portion	1,805,218	1,746,473	1,555,719	869,463	1,020,449
Total Buckeye Partners, L.P. capital (6)	1,392,405	242,334	232,060	238,330	240,617
Accumulated other comprehensive loss (7)	(21,259)				
Noncontrolling interests (3)	17,855	1,209,960	1,166,774	1,066,143	772,525

(1) Substantial increase in revenue for the year ended December 31, 2010 compared to the year ended December 31, 2009 is primarily attributable to increases in commodity prices and sales volumes in our Energy Services segment. 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 Oil Company LLC (Farm & Home) in the first quarter of 2008.

(2) Operating income and net income for the year ended December 31, 2010 include a non-cash charge of $21.1 million related to the modification of an equity compensation plan (see Note 18 in the Notes to Consolidated Financial Statements). 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 organizational restructuring (see Note 3 in the Notes to Consolidated Financial Statements).

(3) Prior to the Merger, noncontrolling interests reported by BGH included equity interests in Buckeye that were not owned by BGH. In connection with the Merger, amounts included in noncontrolling interests in our consolidated balance sheet associated with certain third-party ownership interests in Buckeye were reclassified as limited partners interests.

(4) Earnings per LP Unit diluted is presented only for the period since August 9, 2006, the date BGH became a public company. Pursuant to the Merger, BGH s unitholders received a total of approximately 20.0 million of Buckeye s LP Units in the aggregate in exchange for all outstanding BGH common units and management units. As a result, the number of Buckeye s LP Units outstanding increased from 51.6 million to 71.4 million. However, for historical reporting purposes, the impact of this change was accounted for as a reverse split of BGH s units of 0.705 to 1.0, together with the addition of Buckeye s existing LP Units. Therefore, since BGH was considered the surviving accounting entity, the weighted average number of LP Units outstanding used for basic and diluted earnings per LP Unit calculations are BGH s historical weighted average common units outstanding adjusted for the reverse unit split and the addition of Buckeye s existing LP Units. Amounts reflecting historical BGH unit and per unit amounts included in this Report have been restated for the reverse unit split.

(5) Cash distributions paid represent cash payments by Buckeye for distributions during each of the periods presented.

(6) Total Buckeye capital increased substantially in connection with the Merger with the elimination of noncontrolling interests.

(7) For periods prior to the Merger, amounts in accumulated other comprehensive loss were included in noncontrolling interests.

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 2011;
- 2010 Developments discusses major items impacting our results in 2010;
- 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 provides a description of certain new accounting pronouncements that will or may affect our consolidated financial statements.

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).

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Merger

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

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

Our general partner, Buckeye GP, continues to manage us following the Merger, and our management team remains unchanged. Additionally, three former members of BGH s general partner s board of directors are now members of Buckeye GP s board of directors.

Overview of Business

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

We operate and report in five business segments: Pipeline Operations; Terminalling & Storage; Natural Gas Storage; Energy Services; and Development & Logistics. See Note 23 in the Notes to Consolidated Financial Statements for a more detailed discussion of our business segments.

We own and operate one of the largest independent refined petroleum products pipeline systems in the United States in terms of volumes delivered with approximately 5,400 miles of pipeline and 69 active products terminals that provide aggregate storage capacity of over 53 million barrels. In addition, we recently closed the acquisition of a Bahamian terminal facility with a total installed capacity of approximately 21.6 million barrels. We also operate and maintain approximately 2,600 miles of other pipelines under agreements with major oil and gas, petrochemical and chemical companies, and perform certain engineering and construction management services for third parties. We also own and operate a major natural gas storage facility in northern California, and are a wholesale distributor of refined petroleum products in the United States in areas also served by our pipelines and terminals.

General Outlook for 2011

During 2009 and the first half of 2010, demand for refined petroleum products continued to be adversely impacted by the weakness in the overall economy. In the second half of 2010, year-over-year transportation volumes increased for the first time since 2007. We expect that demand for refined petroleum products will continue to strengthen during 2011 if the overall economy improves.

We expect aggregate rates for our transportation and storage services will show modest increases, particularly in the second half of 2011 as we will realize the benefit of increased tariffs on both our indexed and market-based pipeline systems. Ultimately, our ability to increase transportation and storage revenues is largely dependent on the strength of the overall economy in the markets we serve.

The capital markets continued to strengthen during 2010 and in the first quarter of 2011, compared to 2009. In the fourth quarter of 2010 and the first quarter of 2011, we successfully accessed both the debt and equity markets in order to provide funding for the BORCO acquisition, and we believe that, under current financial market conditions, we could raise additional capital in both the debt and equity markets on acceptable terms.

We expect that our earnings in 2011 will be positively impacted by the full-year contribution from the Puerto Rico and Opelousas terminal acquisitions completed in 2010 and the BORCO acquisition completed in the first quarter of 2011, incremental revenue from growth capital expenditures and the strengthening of the overall economy.

Throughout 2011, 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.

2010 Developments

Major items impacting our results in 2010 include:

Consolidated Statements of Operations

We recognized $2.4 million of expenses related to the write-off in 2010 of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy.

Following the Merger, BGH GP exchanged a portion of the LP Units it received in the Merger for outstanding override units, which override units are part of an equity compensation plan for certain members of BGH GP s senior management, who also served as our senior management. This exchange represented a plan modification and resulted in a non-cash charge of $21.1 million in the 2010 period. See Note 18 in the Notes to Consolidated Financial Statements for further discussion.

In December 2010, we entered into a sale and purchase agreement to acquire an 80% interest in FRBCH, the indirect owner of BORCO, for $1.4 billion. While the transaction closed in 2011, we recognized $6.1 million of expenses in 2010 in the Terminalling & Storage segment, of which $4.1 million of transaction expenses were included in total costs and expenses and $2.0 million of expenses were included in interest and debt expense related to the Bridge Loans. In February 2011, we acquired the remaining 20% interest in FRBCH from Vopak. See Item 1, 2010 Developments for further information.

Consolidated Balance Sheet and Capital Structure

We incurred $16.4 million of costs associated with the Merger in 2010. We charged these costs directly to partners capital. BGH is considered the surviving consolidated entity for accounting purposes, while Buckeye is the surviving consolidated entity for legal and reporting purposes. The Merger was accounted for as an equity transaction. Therefore, changes in BGH s ownership interest as a result of the Merger did not result in gain or loss recognition. See Note 2 in the Notes to Consolidated Financial Statements for further information regarding financial statement preparation.

We completed two acquisitions in 2010 of refined petroleum product terminals from Chevron and Shell for approximately $13.0 million and $32.6 million (net of $3.5 million of cash acquired), respectively, that were financed with borrowings under our Credit Facility. Both acquisitions were included in our Terminalling & Storage segment.

We incurred capital expenditures for internal growth projects of $46.5 million.

We amended the BES Credit Agreement to increase the total commitments for borrowings available to BES up to $500.0 million, subject to an initial limitation of $350.0 million. See Note 13 in the Notes to Consolidated Financial Statements for further information.

Results of Operations

Consolidated Summary

Adjusted EBITDA (as defined below) increased during the year ended December 31, 2010 compared to the year ended December 31, 2009 and during the year ended December 31, 2009 compared to the year ended December 31, 2008. Our revenues, operating income and net income increased during the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily due to contributions from terminals acquired in November 2009 and higher pipeline tariff rates and other pipeline transportation revenues and the recognition of expenses in the 2009 period in connection with our organizational restructuring and a non-cash charge for an asset impairment. Our revenues, operating income and net income 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. Overall pipeline volumes declined by 0.4% during the year ended December 31, 2010 compared to the year ended December 31, 2009 and by 5.2% during the year ended December 31, 2009 compared to the year ended December 31, 2008.

Our summary operating results were as follows for the periods indicated (in thousands, except per LP Unit amounts):

	Year Ended December 31, 2010	2009	2008
Revenues	$ 3,151,268	$ 1,770,372	$ 1,896,652
Costs and expenses	2,871,767	1,566,572	1,650,160
Operating income	279,501	203,800	246,492
Earnings from equity investments	11,363	12,531	7,988
Interest and debt expense	(89,169)	(75,147)	(75,410)
Other income (expense)	(687)	453	1,553
Net income	201,008	141,637	180,623
Less: net income attributable to noncontrolling interests	(157,928)	(92,043)	(154,146)
Net income attributable to Buckeye Partners, L.P.	$ 43,080	$ 49,594	$ 26,477
Earnings per LP Unit diluted (1)	$ 1.65	$ 2.49	$ 1.33

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

Adjusted EBITDA

Adjusted EBITDA is the primary measure used by senior management, including our Chief Executive Officer, to evaluate our operating results and to allocate our resources. We define EBITDA, a measure not defined under GAAP, as net income attributable to our unitholders before interest and debt expense, income taxes and depreciation and amortization. EBITDA should not be considered an alternative to net income, operating income, cash flow from operations or any other measure of financial performance or liquidity presented in accordance with GAAP. The

EBITDA measure eliminates the significant level of non-cash depreciation and amortization expense that results from the capital-intensive nature of our businesses and from intangible assets recognized in business combinations.

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In addition, EBITDA is unaffected by our capital structure due to the elimination of interest and debt expense and income taxes. We define Adjusted EBITDA, which is also a non-GAAP measure, as EBITDA plus: (i) non-cash deferred lease expense, which is the difference between the estimated annual land lease expense for our natural gas storage facility in the Natural Gas Storage segment to be recorded under GAAP and the actual cash to be paid for such annual land lease, (ii) non-cash unit-based compensation expense, (iii) the 2009 non-cash impairment expense of $59.7 million related to the Buckeye NGL Pipeline that we sold in January 2010, (iv) the 2009 expense of $32.1 million for organizational restructuring, (v) the 2010 non-cash BGH GP equity plan modification expense of $21.1 million and (vi) income attributable to noncontrolling interests related to Buckeye for periods prior to the Merger in order to provide consistency and comparability between periods before and after the Merger.

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 be defined differently by other companies. Our senior management uses Adjusted EBITDA to evaluate consolidated operating performance and the operating performance of our business segments and to allocate resources and capital to the business segments. In addition, our senior management uses Adjusted EBITDA as a performance measure to evaluate the viability of proposed projects and to determine overall rates of return on alternative investment opportunities.

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

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,		
	2010	2009	2008
Adjusted EBITDA:			
Pipeline Operations	$ 235,405	$ 229,576	$ 193,940
Terminalling & Storage	106,387	72,588	59,850
Natural Gas Storage	29,794	41,950	41,814
Energy Services	5,861	19,335	9,443
Development & Logistics	5,193	6,718	8,528
Total Adjusted EBITDA	$ 382,640	$ 370,167	$ 313,575
GAAP Reconciliation:			
Net income	$ 201,008	$ 141,637	$ 180,623
Less: net income attributable to noncontrolling interests	(157,928)	(92,043)	(154,146)
Net income attributable to Buckeye Partners, L.P.	43,080	49,594	26,477
Interest and debt expense	89,169	75,147	75,410
Income tax (benefit) expense	(919)	(343)	801
Depreciation and amortization	59,590	54,699	50,834
EBITDA	190,920	179,097	153,522
Net income attributable to noncontrolling interests affected by Merger (for periods prior to Merger) (1)	157,467	90,381	153,546
Non-cash deferred lease expense	4,235	4,500	4,598
Non-cash unit-based compensation expense	8,960	4,408	1,909
Equity plan modification expense	21,058		
Asset impairment expense		59,724	
Reorganization expense		32,057	
Adjusted EBITDA	$ 382,640	$ 370,167	$ 313,575

(1) Amounts represent portions of BGH s noncontrolling interests related to Buckeye that were eliminated as a result of the Merger. Amounts are added back for the portion of 2010 prior to the Merger, and the 2009 and 2008 periods to provide consistency with the 2010 period.

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Segment Results

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

	Year Ended December 31, 2010	2009	2008
Revenues:			
Pipeline Operations	$ 400,926	$ 392,667	$ 387,267
Terminalling & Storage	175,000	136,576	119,155
Natural Gas Storage	95,337	99,163	61,791
Energy Services	2,481,566	1,125,013	1,295,925
Development & Logistics	37,696	34,136	43,498
Intersegment	(39,257)	(17,183)	(10,984)
Total revenues	$ 3,151,268	$ 1,770,372	$ 1,896,652
Total costs and expenses: (1)			
Pipeline Operations	$ 229,331	$ 298,710	$ 237,918
Terminalling & Storage	85,067	75,492	67,022
Natural Gas Storage	79,268	68,589	29,556
Energy Services	2,482,933	1,111,927	1,290,020
Development & Logistics	34,425	29,037	36,628
Intersegment	(39,257)	(17,183)	(10,984)
Total costs and expenses	$ 2,871,767	$ 1,566,572	$ 1,650,160
Depreciation and amortization:			
Pipeline Operations	$ 36,799	$ 35,533	$ 35,188
Terminalling & Storage	9,521	7,258	6,051
Natural Gas Storage	6,594	5,971	4,599
Energy Services	4,933	4,204	3,386
Development & Logistics	1,743	1,733	1,610
Total depreciation and amortization	$ 59,590	$ 54,699	$ 50,834
Asset impairment expense:			
Pipeline Operations	$	$ 59,724	$
Reorganization expense:			
Pipeline Operations	$	$ 26,127	$
Terminalling & Storage		2,735	
Natural Gas Storage		495	
Energy Services		1,207	
Development & Logistics		1,493	
Total reorganization expense	$	$ 32,057	$
Operating income (loss):			
Pipeline Operations	$ 171,595	$ 93,957	$ 149,349

Terminalling & Storage	89,933	61,084	52,133
Natural Gas Storage	16,069	30,574	32,235
Energy Services	(1,367)	13,086	5,905
Development & Logistics	3,271	5,099	6,870
Total operating income	$ 279,501	$ 203,800	$ 246,492

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

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

	Year Ended December 31,		
	2010	2009	2008
Pipeline Operations (average bpd):			
Gasoline	643,700	650,100	673,500
Jet fuel	338,500	336,700	354,700
Diesel fuel	234,400	209,800	230,400
Heating oil	66,900	74,900	73,800
LPGs	18,000	16,500	17,500
NGLs		13,900	20,900
Other products	3,000	8,000	11,400
Total Pipeline Operations	1,304,500	1,309,900	1,382,200
Terminalling & Storage (average bpd):			
Products throughput (1)	564,300	471,900	464,400
Energy Services (in thousands of gallons):			
Sales volumes	1,139,100	655,100	435,200

(1) Reported quantities include volumes from our terminal located in Albany, New York. For the years ended December 31, 2009 and 2008, we previously reported total products throughput of 444.9 thousand and 457.4 thousand barrels, respectively, which excluded volumes from the Albany, New York terminal.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Consolidated

Adjusted EBITDA. Adjusted EBITDA increased by $12.4 million, or 3.4%, to $382.6 million for the year ended December 31, 2010 from $370.2 million for the corresponding period in 2009. The Terminalling & Storage segment and the Pipeline Operations segment were primarily responsible for this increase in Adjusted EBITDA. The Terminalling & Storage segment s Adjusted EBITDA increased by $33.8 million for the year ended December 31, 2010 as compared to the corresponding period in 2009, driven by the contribution from terminals acquired in November 2009 and in the fourth quarter of 2010, the impact of internal growth projects, increased throughput volumes, favorable settlement experience, higher fees, increased storage, rental and other service revenues and lower operating expenses, partially offset by an increase in professional fees related to the BORCO acquisition. The Pipeline Operations segment s Adjusted EBITDA increased by $5.8 million for the year ended December 31, 2010 as compared to the corresponding period in 2009, primarily due to increased tariff rates, favorable settlement experience and increased revenues from pipeline assets acquired, which more than offset the impact of lower volumes transported during the year ended December 31, 2010 compared to the corresponding period in 2009.

These increases in Adjusted EBITDA were partially offset by decreases in Adjusted EBITDA in the Energy Services segment, the Natural Gas Storage segment and the Development & Logistics segment. The Energy Services segment s Adjusted EBITDA decreased by $13.4 million for the year ended December 31, 2010 as compared to the corresponding period in 2009, primarily due to lower margins realized on products sold as a result of weakened market conditions during the year ended December 31, 2010, partially offset by increased volumes of products sold. The Natural Gas Storage segment s Adjusted EBITDA decreased by $12.1 million for the year ended December 31, 2010 as compared to the corresponding period in 2009, as a result of lower natural gas prices, lower price volatility and low lease rates. The Development & Logistics segment s Adjusted EBITDA decreased by $1.5 million for the year ended December 31, 2010 as compared to the corresponding period in 2009, due to $2.4 million of expenses related to the write-off in the 2010 period of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy and due to reduced construction contract services.

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Overall, Adjusted EBTIDA was also impacted favorably by the continued effectiveness of cost control measures we implemented in 2009. Largely as a result of these efforts, costs decreased by approximately $11.7 million during the year ended December 31, 2010 as compared to the corresponding period in 2009. Income from equity investments decreased by $1.1 million for the year ended December 31, 2010 as compared to the corresponding period in 2009 primarily due to lower earnings from WT LPG. The revenue and expense factors affecting the variance in consolidated Adjusted EBITDA are more fully discussed below.

Revenue. Revenue was $3,151.3 million for the year ended December 31, 2010, which is an increase of $1,380.9 million, or 78.0%, from the year ended December 31, 2009. The increase in revenue for the year ended December 31, 2010 as compared to the corresponding period in 2009 was caused primarily by the following:

- an increase of $1,356.6 million in revenue from the Energy Services segment, resulting from an overall increase in refined petroleum product prices and volumes of product sold during the year ended December 31, 2010 as compared to the corresponding period in 2009;

- an increase of $38.4 million in revenue from the Terminalling & Storage segment, resulting from increased revenue from terminals acquired in November 2009 and in the fourth quarter of 2010, increased throughput volumes, increased fees, increased storage and rental revenue, including $5.0 million in storage fees from previously underutilized tankage identified in connection with our best practices initiative and other marketing opportunities, and favorable settlement experience;

- an increase of $8.2 million in revenue from the Pipeline Operations segment, resulting primarily from the benefit of higher tariff rates, favorable settlement experience and increased revenues from pipeline assets acquired in November 2009, partially offset by the impact of slightly lower transportation volumes; and

- an increase of $3.6 million in revenue from the Development & Logistics segment, resulting primarily from the sale of ammonia linefill and from the assignment of certain service contracts from the Pipeline Operations segment to the Development & Logistics segment in April 2010.

The increase in revenue was partially offset by:

- a decrease of $3.9 million in revenue from the Natural Gas Storage segment, resulting primarily from lower fees from hub services transactions recognized as revenue.

Total Costs and Expenses. Total costs and expenses were $2,871.8 million for the year ended December 31, 2010, which is an increase of $1,305.2 million, or 83.3%, from the corresponding period in 2009. Total costs and expenses reflect:

- an increase in refined petroleum product prices, which, coupled with an increase in volume sold, resulted in a $1,371.5 million increase in the Energy Services segment s cost of product sales in 2010 as compared to 2009;

- an increase of $9.6 million in costs and expenses of the Terminalling & Storage segment, resulting primarily from higher operating expense for terminals acquired in November 2009 and in the fourth quarter of 2010, professional fees related to the BORCO acquisition, higher integrity program expenses and higher bad debt expense, partially offset by expenses recognized in 2009 for organizational restructuring, lower environmental remediation expenses and lower payroll and benefits costs;

- an increase of $10.7 million in costs and expenses of the Natural Gas Storage segment, resulting from higher costs associated with hub services transactions recognized as expense caused primarily by general market conditions as discussed above;

- an increase of $5.4 million in costs and expenses of the Development & Logistics segment, primarily resulting from $2.4 million of expenses related to the write-off in the 2010 period of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy and due to the assignment of certain service contracts from the Pipeline Operations segment to the Development & Logistics segment in April 2010;

an increase of $4.9 million in depreciation and amortization, which is not a component of Adjusted EBITDA as presented in the reconciliation above, primarily on assets placed in service in the second half of 2009 in connection with the Kirby Hills Phase II expansion project, on certain internal-use software placed in service in the fourth quarter of 2009 and on assets acquired in November 2009;

an increase of $4.6 million in non-cash unit-based compensation expense, which is not a component of Adjusted EBITDA as presented in the reconciliation above; and

the recognition of $21.1 million of compensation expense in the 2010 period, which is not a component of Adjusted EBITDA as presented in the reconciliation above, related to the modification of an equity compensation plan (see Note 18 in the Notes to Consolidated Financial Statements).

Total costs and expenses in the 2009 period include the recognition of a non-cash $59.7 million asset impairment expense in the Pipeline Operations segment, related to the Buckeye NGL Pipeline and $32.1 million of expenses across all segments associated with organizational restructuring, none of which are components of Adjusted EBITDA as presented in the reconciliation above. Total costs and expenses for the year ended December 31, 2010 reflect the effectiveness of cost management efforts we implemented in 2009.

Total costs and expenses also reflect the following decreases:

a decrease of $69.4 million in costs and expenses of the Pipeline Operations segment, resulting substantially from a decrease related to the asset impairment expense and the organizational restructuring charges recognized in the 2009 period as discussed above, lower contract service activities, lower payroll and benefits costs, which were primarily attributable to the organizational restructuring that occurred in 2009 and resulted in reduced headcount, lower environmental remediation expenses and lower operating power costs due to lower transportation volumes and power contract renegotiations as part of our best practices initiative, partially offset by the recognition of compensation expense related to the modification of an equity compensation plan, higher property and other taxes, higher professional fees and project costs and higher pipeline integrity program expenses.

Income attributable to noncontrolling interests. Income attributable to noncontrolling interests, which through November 19, 2010, the date of the Merger, represented Services Company s equity and equity interests in Buckeye that were not owned by BGH, and includes portions of Sabina and WesPac Memphis that are not owned by Buckeye, was $157.9 million for the year ended December 31, 2010 as compared to $92.0 million in the corresponding period in 2009. As discussed above, the 2009 period includes amounts related to the asset impairment expense and the organizational restructuring charge.

Consolidated net income attributable to unitholders. Consolidated net income attributable to our unitholders was $43.1 million for the year ended December 31, 2010 compared to $49.6 million for the year ended December 31, 2009. Interest and debt expense increased by $14.1 million for the year ended December 31, 2010 as compared to the corresponding period in 2009, due to $2.0 million of interest expense related to a bridge facility entered into in anticipation of the BORCO transaction, interest expense related to the $275.0 million aggregate principal amount of 5.500% Notes due 2019 issued in August 2009 (the 5.500% Notes), higher outstanding borrowings under the BES Credit Agreement and the Credit Facility and lower interest capitalized on construction projects. Other revenue and expense items impacting operating income are discussed above.

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

Pipeline Operations

Adjusted EBITDA. Adjusted EBITDA from the Pipeline Operations segment of $235.4 million for the year ended December 31, 2010 increased by $5.8 million, or 2.5%, from $229.6 million for the corresponding period in 2009. The increase in Adjusted EBITDA was driven primarily by an $8.9 million benefit of higher tariff rates, favorable settlement experience of $4.9 million, increased revenues of $2.4 million from pipeline assets acquired in November 2009 and an increase of $3.4 million in other pipeline revenues. These increases in Adjusted EBITDA were partially offset by lower volumes transported during the year ended December 31, 2010, due in part to the sale of the Buckeye NGL Pipeline on January 1, 2010, which resulted in a $5.5 million decrease in transportation revenues compared with the corresponding period in 2009, a $5.9 million decrease in revenue from a product supply arrangement with a wholesale distributor and contract service activities at customer facilities as discussed below, a

$1.1 million decrease in income from equity investments and a $1.4 million increase in operating expenses. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Pipeline Operations segment was $400.9 million for the year ended December 31, 2010, which is an increase of $8.2 million, or 2.1%, from the corresponding period in 2009. Revenues increased due to the $8.9 million benefit of higher tariff rates resulting from overall average tariff rate increases of approximately 3.8% implemented on July 1, 2009 and 2.6% implemented on May 1, 2010, favorable settlement experience of $4.9 million, increased revenues of $2.4 million from pipeline assets acquired in November 2009 and an increase of $3.4 million in other pipeline revenues. These increases were partially offset by a 0.4% decrease in transportation volumes, which resulted in a $5.5 million decrease in transportation revenues, due in part to the sale of the Buckeye NGL Pipeline on January 1, 2010 and a $5.9 million decrease in revenue from a product supply arrangement with a wholesale distributor and contract service activities at customer facilities connected to our refined petroleum products pipelines pursuant to the assignment of such service contract to the Development & Logistics segment.

Total Costs and Expenses. Total costs and expenses from the Pipeline Operations segment were $229.3 million for the year ended December 31, 2010, which is a decrease of $69.4 million, or 23.2%, from the corresponding period in 2009. Total costs and expenses for the 2009 period include a $59.7 million non-cash asset impairment expense related to the Buckeye NGL Pipeline and $26.1 million of expense related to organizational restructuring. These charges in the year ended December 31, 2009 were the primary reason that total costs and expenses in the 2009 period were 23.2% higher than in the 2010 period. The asset impairment expense and the organizational restructuring charges are not components of Adjusted EBITDA as presented in the reconciliation above.

Excluding the non-cash asset impairment expense and the expense related to the organizational restructuring, total costs and expenses in the 2010 period were higher than in the 2009 period as a result of the recognition of $11.8 million of compensation expense related to the modification of an equity compensation plan, a $5.6 million increase in professional fees, outside services and other project expenses, a $4.1 million increase in property and other taxes, as the 2009 period included the benefit of a favorable $7.2 million tax settlement with the City of New York, a $2.4 million increase in pipeline integrity program expenses, a $1.3 million increase in depreciation and amortization as a result of pipeline assets acquired in November 2009 and a $0.6 million increase in bad debt expense. Depreciation and amortization expense and the expense related to the modification of the equity compensation plan are not components of Adjusted EBITDA as presented in the reconciliation above.

These increases in total costs and expenses were partially offset by a $4.5 million decrease in contract service activities due to the assignment of certain operating service contracts from the Pipeline Operations segment to the Development & Logistics segment, a $2.0 million decrease in environmental remediation expenses, a $1.3 million decrease in product costs, resulting from reduced volumes of product sold to a wholesale distributor, a $1.1 million decrease in payroll and benefits costs, resulting primarily from our best practices initiative, and a $0.6 million decrease in operating power costs due to lower transportation volumes and power contract renegotiations as part of our best practices initiative.

Operating Income. Operating income from the Pipeline Operations segment was $171.6 million for the year ended December 31, 2010 compared to operating income of $94.0 million for the year ended December 31, 2009. Revenue and expense items impacting operating income are discussed above.

Terminalling & Storage

Adjusted EBITDA. Adjusted EBITDA from the Terminalling & Storage segment of $106.4 million for the year ended December 31, 2010 increased by $33.8 million, or 46.6%, from $72.6 million for the corresponding period in 2009. The increase in Adjusted EBITDA reflects an increase of $38.4 million in revenues from the contribution of terminals acquired in November 2009 and in the fourth quarter of 2010, the impact of internal growth projects, increased throughput volumes, favorable settlement experience, higher fees and increased storage, rental and other service revenue, partially offset by a $4.6 million increase in operating expenses. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Terminalling & Storage segment was $175.0 million for the year ended December 31, 2010, which is an increase of $38.4 million, or 28.1%, from the corresponding period in 2009. Approximately

$34.1 million of the increase resulted primarily from terminals acquired in November 2009 and in the fourth quarter of 2010, internal growth projects, increased throughput volumes, higher fees and higher storage and rental revenue, including $5.0 million in storage fees from previously underutilized tankage identified in connection with our best practices initiative and other marketing opportunities. Also contributing to the improved revenue was an increase of $4.3 million in settlement experience, reflecting the favorable impact of higher refined petroleum product prices during the year ended December 31, 2010 as compared to the corresponding period in 2009. Overall terminalling volumes increased 19.6%, of which 14.4% resulted from the acquisition of terminals in November 2009 and in the fourth quarter of 2010, and the remaining 5.2% was primarily due to increased diesel, ethanol and jet fuel throughput volumes.

Total Costs and Expenses. Total costs and expenses from the Terminalling & Storage segment were $85.1 million for the year ended December 31, 2010, which is an increase of $9.6 million, or 12.7%, from the corresponding period in 2009. The increase in total costs and expenses in the 2010 period as compared to the 2009 period is due to the recognition of $4.6 million of compensation expense related to an equity plan modification, a $4.7 million increase in operating expenses for terminals acquired in November 2009 and in the fourth quarter of 2010, a $4.1 million increase in professional fees related to the BORCO acquisition, a $2.2 million increase in depreciation and amortization, primarily on terminals acquired in November 2009, a $0.6 million increase in bad debt expense and a $0.6 million increase in integrity program expenses. These increases in total costs and expenses were partially offset by a $2.7 million decrease related to expenses for organizational restructuring recognized in the 2009 period, a $2.1 million decrease in payroll and benefits costs primarily related to our best practices initiative in 2009, a $1.1 million decrease in environmental remediation expenses, a $0.6 million decrease in other professional fees, outside service and other costs and a $0.8 million decrease in property and other taxes. Depreciation and amortization expense, the expense related to the modification of the equity compensation plan and the organizational restructuring charge are not components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the Terminalling & Storage segment was $89.9 million for the year ended December 31, 2010 compared to operating income of $61.1 million for the year ended December 31, 2009. Revenue and expense items impacting operating income are discussed above.

Natural Gas Storage

Adjusted EBITDA. Adjusted EBITDA from the Natural Gas Storage segment of $29.8 million for the year ended December 31, 2010 decreased by $12.1 million, or 29.0%, from $41.9 million for the corresponding period in 2009. The decrease in Adjusted EBITDA was primarily the result of a decrease of $14.5 million in the net contribution from hub service activities and a decrease of $0.4 million in lease revenues, partially offset by a decrease of $2.8 million in operating expenses during the year ended December 31, 2010. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Natural Gas Storage segment was $95.3 million for the year ended December 31, 2010, which is a decrease of $3.9 million, or 3.9%, from the corresponding period in 2009. This overall decrease is attributable to lower fees recognized as revenue and lower underlying volume for hub services provided during the year ended December 31, 2010. During the years ended December 31, 2010 and 2009, there were 434 and 337 outstanding hub service contracts, respectively, for which revenue was being recognized ratably. Market conditions resulted in a decrease of $3.5 million in fees for hub service agreements recognized as revenue during the year ended December 31, 2010 as compared to the corresponding period in 2009. Lease revenue decreased $0.4 million for the year ended December 31, 2010, as a decrease in the fee charged for each volumetric unit of storage capacity leased was partially offset by increased storage capacity from the commissioning of the Kirby Hills Phase II expansion project, which was placed in service in June 2009.

Total Costs and Expenses. Total costs and expenses from the Natural Gas Storage segment were $79.3 million for the year ended December 31, 2010, which is an increase of $10.7 million, or 15.6%, from the corresponding period in 2009. Costs of natural gas storage services, which includes hub services fees paid to customers for hub service activities, increased $11.1 million, which is the primary driver of the increase in expenses. Total costs and expenses also include the recognition of $1.9 million of compensation expense related to the modification of an equity compensation plan, a $0.7 million increase in fuel costs, a $0.6 million increase in depreciation and amortization primarily due to assets placed in service in the second half of 2009 in connection with the Kirby Hills

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Phase II expansion project, a $0.3 million increase in payroll related costs and a $0.3 million increase in property and other tax expense, partially offset by a $3.7 million decrease in outside service costs and other expenses and a $0.5 million decrease related to organizational restructuring charges recognized in the 2009 period. The organizational restructuring charge, depreciation and amortization and the expense related to the modification of the equity compensation plan are not components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the Natural Gas Storage segment was $16.1 million for the year ended December 31, 2010 compared to operating income of $30.6 million for the year ended December 31, 2009. Revenue and expense items impacting operating income are discussed above.

Energy Services

Adjusted EBITDA. Adjusted EBITDA from the Energy Services segment of $5.9 million for the year ended December 31, 2010 decreased by $13.4 million, or 69.7%, from $19.3 million for the corresponding period in 2009. The decrease in Adjusted EBITDA was driven by lower rack margins and fewer opportunities to optimize our storage capacity as opportunistic prices for holding product in inventory were not as prevalent in 2010, as compared to 2009. At the rack, sales volumes were 73.9% higher than 2009; however, competitive pricing and an abundance of supply suppressed rack margins throughout the first half of the year. Rack margins began to rebound in the second half of the year as we entered the heating season, and inventory levels were being pulled down followed by a rise in crude oil prices; however, the increased margins in the second half of 2010 were not enough to overcome the lower margins recognized in the first half of 2010. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Energy Services segment was $2,481.6 million for the year ended December 31, 2010, which is an increase of $1,356.6 million, or 120.6%, from the corresponding period in 2009. The increase in revenue was primarily due to an increase in refined petroleum product prices in the 2010 period, which correspondingly increased the cost of product sales, and an increase of 73.9% in sales volumes.

Total Costs and Expenses. Total costs and expenses from the Energy Services segment were $2,482.9 million for the year ended December 31, 2010, which is an increase of $1,371.0 million, or 123.3%, from the corresponding period in 2009. The increase in total costs and expenses was primarily due to a $1,371.5 million increase in cost of product sales as a result of increased volumes sold and an increase in refined petroleum product prices, the recognition of $1.1 million of compensation expense related to the modification of an equity compensation plan, a $1.3 million increase in payroll related costs, a $1.1 million increase in bad debt expense, a $0.7 million increase in depreciation and amortization related primarily to certain internal-use software placed in service in the fourth quarter of 2009 and a $0.5 million increase in property and other tax expense, partially offset by a $3.8 million decrease in professional fees, repairs and maintenance and other expenses and a $1.2 million decrease related to an organizational restructuring recognized in the 2009 period. The organizational restructuring charge, depreciation and amortization, and the expense related to the modification of the equity compensation plan are not components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income (Loss). Operating loss from the Energy Services segment was $1.4 million for the year ended December 31, 2010 compared to operating income of $13.1 million for the year ended December 31, 2009. Revenue and expense items impacting operating income (loss) are discussed above.

Development & Logistics

Adjusted EBITDA. Adjusted EBITDA from the Development & Logistics segment of $5.2 million for the year ended December 31, 2010 decreased by $1.5 million, or 22.7%, from $6.7 million for the corresponding period in 2009, primarily due to reduced construction contract margins of $3.4 million, which includes the recognition of $2.4 million of expenses related to the write-off in the 2010 period of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy, partially offset by a net increase of $1.2 million related to the sale of ammonia linefill and increased operating contract margins of $0.6 million. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Development & Logistics segment was $37.7 million for the year ended December 31, 2010, which is an increase of $3.6 million, or 10.4%, from the corresponding period in 2009. The increase in revenue was primarily due to the recognition of $1.2 million of revenue related to the sale of ammonia linefill, a $5.4 million increase in operating service revenues and other revenues from the 2009 period, primarily due to the assignment of certain service contracts from the Pipeline Operations segment to the Development & Logistics segment, a $1.1 million increase in operating service revenues as a result of higher fees and increased reimbursable costs and a $0.4 million increase in rental and transportation revenues. These increases in revenue were partially offset by reduced construction contract activity following completion of certain construction projects in 2009, resulting in a $4.5 million reduction in construction contract revenues.

Total Costs and Expenses. Total costs and expenses from the Development & Logistics segment were $34.4 million for the year ended December 31, 2010, which is an increase of $5.4 million, or 18.6%, from the corresponding period in 2009. Total costs and expenses increased as a result of the recognition of $2.4 million of expenses related to the write-off in the 2010 period of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy, the recognition of $1.9 million of compensation expense related to the modification of an equity compensation plan and increased operating services activities discussed above, partially offset by $1.5 million of expense related to an organizational restructuring recognized in the 2009 period, reduced contract construction activity discussed above and an increase in income tax benefit of $0.6 million, primarily related to the write-off of a portion of an outstanding receivable balance and other costs associated with a customer bankruptcy. The organizational restructuring charge, the expense related to the modification of the equity compensation plan and the income tax benefit are not components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the Development & Logistics segment was $3.3 million for the year ended December 31, 2010 compared to operating income of $5.1 million for the year ended December 31, 2009. Revenue and expense items impacting operating income are discussed above.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Consolidated

Adjusted EBITDA. Adjusted EBITDA increased by $56.6 million, or 18.0%, to $370.2 million for the year ended December 31, 2009 from $313.6 million for the corresponding period in 2008. The Pipeline Operations segment, the Terminalling & Storage segment and the Energy Services segment contributed to this increase in Adjusted EBITDA. The Pipeline Operations segment s Adjusted EBITDA increased by $35.7 million during the year ended December 31, 2009 as compared to the corresponding period in 2008, 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 & Storage segment s Adjusted EBITDA increased by $12.7 million during the year ended December 31, 2009 as compared to the corresponding period in 2008, 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 by $9.9 million during the year ended December 31, 2009 as compared to the corresponding period in 2008, as a result of increased volumes and improved margins. The Natural Gas Storage segment s Adjusted EBITDA remained relatively consistent in 2009 as compared to 2008 with 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 affecting the results for the period.

These increases in Adjusted EBITDA were partially offset by a decrease in Adjusted EBITDA in the Development & Logistics segment. The Development & Logistics segment s Adjusted EBITDA decreased by $1.8 million during the year ended December 31, 2009 as compared to the corresponding period in 2008, as a result of reduced operating services and construction revenues.

Overall, Adjusted EBITDA was also impacted favorably by the continued effectiveness of cost control measures we implemented in 2009. Largely as a result of these efforts, combined with the delay of certain non-critical maintenance activities, overall spending levels decreased $5.0 million during the year ended December 31, 2009 as compared to the corresponding period in 2008. Income from equity investments increased by $4.5 million

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for the year ended December 31, 2009 as compared to the corresponding period in 2008. The revenue and expense factors affecting the variance in consolidated Adjusted EBITDA are more fully discussed below.

Revenue. 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. The decrease in revenue for the year ended December 31, 2009 as compared to the corresponding period in 2008 was caused primarily by the following:

- a decrease of $170.9 million in revenue from the Energy Services segment, due to an overall reduction in refined petroleum product prices during the year ended December 31, 2009 as compared to the corresponding period in 2008; and
- a decrease of $9.4 million in revenue from the Development & Logistics segment, primarily due to decreased construction activities.

The decrease in revenue was partially offset by:

- an increase of $37.4 million in revenue from the Natural Gas Storage segment, resulting primarily from increased activity from the commencement of operations of the Kirby Hills Phase II expansion project;
- an increase of $17.4 million in revenue from the Terminalling & Storage segment, resulting primarily from terminals acquired at various times in 2008 and in November of 2009, increased fees and storage and rental revenue growth; and
- an increase of $5.4 million in revenue from the Pipeline Operations segment, primarily due to increased tariffs and more favorable settlement experience, partially offset by lower volumes.

Total Costs and Expenses. Total costs and expenses were $1,566.6 million for the year ended December 31, 2009, which is a decrease of $83.6 million, or 5.1%, from the corresponding period in 2008. Total costs and expenses reflect:

- a decrease in refined petroleum product prices, which resulted in a $178.1 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; and
- 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, which is not a component of Adjusted EBITDA as presented in the reconciliation above (see Note 8 in the Notes to Consolidated Financial Statements);
- a $32.1 million reorganization expense, which is not a component of Adjusted EBITDA as presented in the reconciliation above (see Note 3 in the Notes to Consolidated Financial Statements);
- a $3.9 million increase in depreciation and amortization, which is not a component of Adjusted EBITDA as presented in the reconciliation above, 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;
- increased operating costs for terminals acquired at various times in 2008 and in November of 2009 in the Terminalling & 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.

Income attributable to noncontrolling interests. Income attributable to noncontrolling interests, which represented Services Company equity and equity interests in Buckeye that were not owned by BGH, and also includes portions of Sabina and WesPac Memphis that are not owned by Buckeye, was $92.0 million for the year ended December 31, 2009 as compared to $154.1 million in the corresponding period in 2008. The 2009 period includes amounts related to the asset impairment expense and the organizational restructuring charge.

Consolidated net income attributable to unitholders. Consolidated income attributable to our unitholders was $49.6 million for the year ended December 31, 2009 compared to $26.5 million for the year ended December 31, 2008. Interest and debt expense decreased by $0.3 million for the year ended December 31, 2009 as compared to the corresponding period in 2008, primarily due to the $275.0 million aggregate principal amount of the 5.500% Notes, which were issued in August 2009. Other revenue and expense items impacting operating income are discussed above.

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

Pipeline Operations

Adjusted EBITDA. Adjusted EBITDA from the Pipeline Operations segment of $229.6 million for the year ended December 31, 2009 increased by $35.7 million, or 18.4%, from $193.9 million for the corresponding period in 2008. The increase in Adjusted EBITDA was primarily due to 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 $4.5 million decrease in maintenance and other expenses 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. Revenue from the Pipeline Operations segment 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 increased $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. Total costs and expenses from the Pipeline Operations segment were $298.7 million for the year ended December 31, 2009, which is an increase of $60.8 million, or 25.6%, from the corresponding period in 2008. Total costs and expenses include $59.7 million of asset impairment expense, $26.2 million of reorganization expense and an increase of $0.3 million in depreciation and amortization, all of which are not components of Adjusted EBITDA as presented in the reconciliation above. Total costs and expenses also include a decrease of $6.6 million in property taxes primarily due to a favorable property tax settlement with the City of New York of $7.2 million, a $12.0 million decrease in product costs as a result of reduced product volumes sold to a wholesale distributor, a $2.9 million decrease in contract service activities at customer facilities connected to our refined petroleum products pipelines, a $2.8 million decrease in operating power due to a decrease in volumes and a $1.7 million decrease in professional fees. These decreases were partially offset by a $2.7 million increase in integrity program expenses.

Operating Income. Operating income from the Pipeline Operations segment was $94.0 million for the year ended December 31, 2009 compared to operating income of $149.3 million for the year ended December 31, 2008. Revenue and expense items impacting operating income are discussed above.

Terminalling & Storage

Adjusted EBITDA. Adjusted EBITDA from the Terminalling & Storage segment of $72.6 million for the year ended December 31, 2009 increased by $12.7 million, or 21.3%, from $59.9 million for the corresponding period in 2008. The increase in Adjusted EBITDA reflects the contribution from terminals acquired in 2009 and 2008 of $9.6 million, including the terminals acquired 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 higher expenses of $1.4 million. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

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Revenue. Revenue from the Terminalling & Storage segment 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 a $14.1 million increase in fees, storage and rental revenue and $11.2 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), partially offset by a $7.9 million decrease in settlement experience.

Total Costs and Expenses. Total costs and expenses from the Terminalling & Storage segment were $75.5 million for the year ended December 31, 2009, which is an increase of $8.5 million, or 12.6%, from the corresponding period in 2008. Total costs and expenses include $2.7 million of reorganization expense and a $1.2 million increase in depreciation and amortization, which are not components of Adjusted EBITDA as presented in the reconciliation above. Depreciation and amortization increased $1.2 million for the year ended December 31, 2009 as a result of terminals acquired at various times in 2008. Total costs and expenses also include a $4.5 million increase in operating expenses for terminals acquired at various times in 2008 and in November of 2009 and an increase in remediation expenses and integrity program expenses totaling $2.3 million.

Operating Income. Operating income from the Terminalling & Storage segment was $61.1 million for the year ended December 31, 2009 compared to operating income of $52.1 million for the year ended December 31, 2008. Revenue and expense items impacting operating income are discussed above.

Natural Gas Storage

Adjusted EBITDA. Adjusted EBITDA from the Natural Gas Storage segment of $41.9 million for the year ended December 31, 2009 increased by $0.1 million, or 0.3%, from $41.8 million for the corresponding period in 2008. The slight increase in Adjusted EBITDA was primarily a result of increased revenues from hub services activities, partially offset by 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. Revenue from the Natural Gas Storage segment 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. Total costs and expenses from the Natural Gas Storage segment were $68.6 million for the year ended December 31, 2009, which is an increase of $39.0 million, or 132.1%, from the corresponding period in 2008. Total costs and expenses include $0.5 million of reorganization expense and an increase of $1.4 million in depreciation and amortization, which are not components of Adjusted EBITDA as presented in the reconciliation above. Depreciation and amortization increased $1.4 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. 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. Operating income from the Natural Gas Storage segment was $30.6 million for the year ended December 31, 2009 compared to operating income of $32.2 million for the year ended December 31, 2008. Revenue and expense items impacting operating income are discussed above.

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Energy Services

Adjusted EBITDA. Adjusted EBITDA from the Energy Services segment of $19.3 million for the year ended December 31, 2009 increased by $9.9 million, or 104.8%, from $9.4 million for the corresponding period in 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. Revenue from the Energy Services segment 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. Total costs and expenses from the Energy Services segment were $1,111.9 million for the year ended December 31, 2009, which is a decrease of $178.1 million, or 13.8%, from the corresponding period in 2008. Total costs and expenses include $1.2 million of reorganization expense and an increase of $0.8 million in depreciation and amortization, which are not components of Adjusted EBITDA as presented in the reconciliation above. 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. 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 corresponding 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. Operating income from the Energy Services segment was $13.1 million for the year ended December 31, 2009 compared to operating income of $5.9 million for the year ended December 31, 2008. Revenue and expense items impacting operating income are discussed above.

Development & Logistics

Adjusted EBITDA. Adjusted EBITDA from the Development & Logistics segment of $6.7 million for the year ended December 31, 2009 decreased by $1.8 million, or 21.2%, from $8.5 million for the corresponding period in 2008. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Development & Logistics segment 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. Total costs and expenses from the Development & Logistics segment were $29.0 million for the year ended December 31, 2009, which is a decrease of $7.6 million, or 20.7%, from the corresponding period in 2008. Total costs and expenses include $1.5 million of reorganization expense, which is not a component of Adjusted EBITDA as presented in the reconciliation above. Depreciation and amortization of $1.7 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. 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. Operating income from the Development & Logistics segment was $5.1 million for the year ended December 31, 2009 compared to operating income of $6.9 million for the year ended December 31, 2008. Revenue and expense items impacting operating income are discussed above.

Liquidity and Capital Resources

General

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to partners. Our principal sources of liquidity are cash from operations, borrowings under our Credit Facility and proceeds from the issuance of our LP Units. We will, from time to time, issue debt securities to permanently finance amounts borrowed under the Credit Facility. BES funds its working capital needs principally from its operations and the BES Credit Agreement. Our financial policy has been to fund sustaining capital expenditures with cash from operations. Expansion and cost improvement capital expenditures, along with acquisitions, have typically been funded from external sources including the Credit Facility as well as debt and equity offerings. Our goal has been to fund at least half of these expenditures with proceeds from equity offerings in order to maintain our investment-grade credit rating.

In June 2010, BES amended and restated the BES Credit Agreement to increase the total commitments for borrowings available to BES up to $500.0 million and extend the maturity date to 2013.

In 2011, we completed the purchase of First Reserve s and Vopak s interests in FRBCH for approximately $1.7 billion in cash and equity. In order to fund a portion of the combined purchase price, in January 2011, we accessed the capital markets through a $650.0 million note issuance due 2021. The notes were issued at 99.62% of their principal amount. In addition, in January 2011, we issued 5,794,725 LP Units and 1,314,870 Class B Units to institutional investors for aggregate consideration of approximately $425.0 million. The proceeds from the debt offering and these equity issuances were used to fund a portion of the BORCO acquisition. The remaining purchase price for the BORCO acquisition was funded through the issuance of LP Units and Class B Units to both First Reserve and Vopak, cash on hand and borrowings under our Credit Facility.

As a result of our actions in 2010 and 2011 and the fact that no debt facilities mature prior to 2012 (excluding the 3.60% ESOP Notes, which mature in March 2011), we believe that availabilities under our Credit Facility and the BES Credit Agreement, coupled with ongoing cash flows from operations, will be sufficient to fund our operations for the remainder of 2011, including any expansion plans for the BORCO terminal facility. We will continue to evaluate a variety of financing sources, including the debt and equity markets described above, throughout 2011.

Debt

At December 31, 2010, we had $13.6 million of cash and cash equivalents on hand and approximately $487.2 million of available credit under the Credit Facility, after application of the facility s funded debt ratio covenant. In addition, at December 31, 2010, BES had $59.7 million of available credit under the BES Credit Agreement, pursuant to certain borrowing base calculations under that agreement.

At December 31, 2010, we had an aggregate face amount of $1,808.8 million of debt, which consisted of the following:

- $300.0 million of 4.625% Notes due 2013 (the 4.625% Notes);
- $275.0 million of 5.300% Notes due 2014 (the 5.300% Notes);
- $125.0 million of 5.125% Notes due 2017 (the 5.125% Notes);
- $300.0 million of 6.050% Notes due 2018 (the 6.050% Notes);
- $275.0 million of 5.500% Notes due 2019;
- $150.0 million of 6.750% Notes due 2033 (the 6.750% Notes);
- $1.5 million of Services Company s 3.60% Senior Secured Notes due March 28, 2011, payable by the ESOP to a third-party lender (the 3.60% ESOP Notes);
- $98.0 million outstanding under the Credit Agreement; and

$284.3 million outstanding under the BES Credit Agreement.

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See Note 13 in the Notes to Consolidated Financial Statements for more information about the terms of the debt discussed above.

On January 13, 2011, we sold the 4.875% Notes in an underwritten public offering. The notes were issued at 99.62% of their principal amount. Total proceeds from this offering, after underwriters fees, expenses and debt issuance costs of $4.5 million, were approximately $643.0 million, and were used to fund a portion of the purchase price for our acquisition of BORCO. See Note 26 in the Notes to Consolidated Financial Statements for further discussion of the BORCO acquisition.

The fair values of our aggregate debt and credit facilities were estimated to be $1,897.5 million and $1,769.8 million at December 31, 2010 and 2009, respectively. The fair values of the fixed-rate debt were estimated by observing market trading prices and by comparing the historic market prices of our publicly-issued debt with the market prices of other MLPs publicly-issued debt with similar credit ratings and terms. The fair values of our variable-rate debt are their carrying amounts, as the carrying amount reasonably approximates fair value due to the variability of the interest rates.

Equity

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

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.

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,		
	2010	**2009**	**2008**
Cash provided by (used in):			
Operating activities	$ 292,479	$ 47,662	$ 208,557
Investing activities	(114,188)	(144,203)	(735,776)
Financing activities	(202,239)	72,834	494,014

Operating Activities

2010 Compared to 2009. Net cash flow provided by operating activities was $292.5 million for the year ended December 31, 2010 compared to $47.7 million for the year ended December 31, 2009. The following were the principal factors impacting net cash flows provided by operating activities for the year ended December 31, 2010:

The net change in fair values of derivatives was a decrease of $45.6 million to cash flows from operating activities for the year ended December 31, 2010, resulting from the decrease in value related to futures contracts executed to hedge physical inventory. The offsetting adjustment is made to the value of inventory by adjusting inventory to current market prices.

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The net impact of working capital changes was an increase of $32.7 million to cash flows from operating activities for the year ended December 31, 2010. The principal factors affecting the working capital changes were:

Accrued and other current liabilities increased by $30.4 million primarily due to increases in unearned revenue primarily in the Natural Gas Storage segment as a result of increased hub services contracts during 2010 for which the customer is billed up front for services provided over the entire term of the contract, an increase in liabilities primarily due to costs incurred for the BORCO transaction and increases in property and other taxes, partially offset by the payment of accrued ammonia purchases during 2010 and a reduction in the reorganization accrual.

Prepaid and other current assets decreased by $16.4 million primarily due to a decrease in unbilled revenue within our Natural Gas Storage segment reflecting billings to counterparties in accordance with terms of their storage agreements, a decrease in margin deposits on futures contracts in our Energy Services segment as a result of increased commodity prices during 2010 (increased commodity prices result in an increase in our broker equity account and therefore less margin deposit is required) and a decrease in receivables related to ammonia contracts.

Accounts payable increased by $11.8 million primarily due to higher payable balances at December 31, 2010 as a result of increased trading activity at BES resulting from increased volumes and increased commodity prices during 2010.

Inventories decreased by $10.0 million due to a decrease in volume of hedged inventory stored by the Energy Services segment. From time to time, the Energy Services segment stores hedged inventory to attempt to capture value when market conditions are economically favorable.

Construction and pipeline relocation receivables decreased by $7.3 million primarily due to a decrease in construction activity in 2010.

Trade receivables increased by $43.1 million primarily due to the timing of collections from customers, partially offset by increased activity from our Energy Services segment due to higher volumes and higher commodity prices during 2010.

2009 Compared to 2008. Net cash flow provided by operating activities was $47.7 million for the year ended December 31, 2009 compared to $208.6 million for the year ended December 31, 2008. The following were the principal factors impacting net cash flows provided by operating activities for the year ended December 31, 2009:

We recognized $32.1 million of reorganization expenses during the year ended December 31, 2009.

The net change in fair values of derivatives was an increase of $20.5 million to cash flows from operating activities for the year ended December 31, 2009, resulting from the decrease in value related to fixed-price 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 $229.7 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 by $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 by $44.1 million primarily due to increased activity from our Energy Services segment due to higher volumes in 2009.

Prepaid and other current assets increased by $28.9 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 decreased by $1.3 million primarily due to costs related to the reorganization.

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Accounts payable increased by $14.6 million due to activity within the Energy Services segment.

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

Investing Activities

2010 Compared to 2009. Net cash flow used in investing activities was $114.2 million for the year ended December 31, 2010 compared to $144.2 million for the year ended December 31, 2009. The following were the principal factors resulting in the $30.0 million decrease in net cash flows used in investing activities:

Capital expenditures decreased by $9.6 million for the year ended December 31, 2010 compared with the year ended December 31, 2009. See below for a discussion of capital spending.

We acquired additional shares of West Shore common stock from an affiliate of BP plc for $13.5 million, resulting in an increase in our ownership interest in West Shore from 24.9% to 34.6%.

We contributed $3.9 million to WT LPG during the year ended December 31, 2009 for our pro-rata share of an expansion project required to meet increased pipeline demand caused by increased product production in the Fort Worth basin and East Texas regions.

During the year ended December 31, 2010, we acquired two refined petroleum product terminals from Chevron and Shell for approximately $13.0 million and $32.6 million (net of $3.5 million of cash acquired), respectively, and we also acquired pipeline assets for $1.3 million. During the year ended December 31, 2009, we acquired refined petroleum product terminals and pipeline assets from ConocoPhillips for $54.4 million. See Note 4 in the Notes to Consolidated Financial Statements for further information.

Cash proceeds from the sale of the Buckeye NGL Pipeline were $22.0 million during the year ended December 31, 2010.

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:

We acquired refined petroleum product terminals and pipeline assets from ConocoPhillips for $54.4 million during the year ended December 31, 2009. During the year ended December 31, 2008, cash used for acquisitions, net of cash acquired, was $667.5 million, consisting of the following: (i) $438.8 million for the acquisition of Lodi Gas, (ii) $143.3 million for the acquisition of Farm & Home and (iii) an aggregate of $75.6 million 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. See Note 4 in the Notes to Consolidated Financial Statements for further information.

We contributed $3.9 million and $9.8 million to WT LPG during the years ended December 31, 2009 and 2008, respectively.

Capital expenditures decreased by $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 the retail operations of Farm & Home were $52.6 million during the year ended December 31, 2008.

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

	Year Ended December 31,		
	2010	**2009**	**2008**
Sustaining capital expenditures	$ 31,244	$ 23,496	$ 28,936
Expansion and cost reduction	46,455	63,813	91,536
Total capital expenditures, net	$ 77,699	$ 87,309	$ 120,472

In 2010, expansion and cost reduction projects included terminal ethanol and butane blending, new pipeline connections, natural gas storage well recompletions, continued progress on a new pipeline and terminal billing system as well as various other operating infrastructure projects. 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 totaled approximately $17.0 million.

Excluding capital expenditures related to the BORCO facility, we expect to spend approximately $110.0 million to $130.0 million for capital expenditures in 2011, of which approximately $30.0 million to $40.0 million is expected to relate to sustaining capital expenditures and $80.0 million to $90.0 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 2011 will include completion of additional storage tanks in the Midwest, the refurbishment of storage and facilities in the Northeast, vapor recovery units throughout our system of terminals and various upgrades and expansions of our ethanol business. Cost reduction expenditures improve operational efficiencies or reduce costs.

We expect to spend approximately $200.0 million to $250.0 million for capital expenditures in 2011 related to the BORCO facility, of which $185.0 million to $225.0 million is expected to relate to expansion projects and $15.0 million to $25.0 million is expected to relate to sustaining capital expenditures. Major expansion expenditures in 2011 is expected to include upgrades and expansions of the jetty structure, the inland dock and berth developments and terminal storage tank expansion projects.

Financing Activities

2010 Compared to 2009. Net cash flow used in financing activities was $202.2 million for the year ended December 31, 2010 compared to net cash flow provided by financing activities of $72.8 million for the year ended December 31, 2009. The following were the principal factors resulting in the $275.0 million increase in net cash flows used in financing activities:

We borrowed $298.4 million and $317.1 million and repaid $278.4 million and $537.4 million under the Credit Facility during the years ended December 31, 2010 and 2009, respectively. Repayments under the Services Company 3.60% ESOP Notes were $6.2 million and $6.3 million during the years ended December 31, 2010 and 2009, respectively. There were no borrowings or repayments under the BGH unsecured revolving credit facility (BGH Credit Agreement) in 2010 and 2009.

Net borrowings under the BES Credit Agreement were $44.5 million and $143.8 million during the years ended December 31, 2010 and 2009, respectively.

We incurred $3.6 million of debt issuance costs during the year ended December 31, 2010 primarily related to the amendment to the BES Credit Agreement in June 2010 (see Note 13 in the Notes to Consolidated Financial Statements).

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.

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We received $4.8 million and $3.2 million in net proceeds from the exercise of LP Unit options during the years ended December 31, 2010 and 2009, respectively. We received $104.6 million in net proceeds from an underwritten equity offering in March and April of 2009 for the public issuance of 3.0 million LP Units.

Cash distributions paid to partners of BGH increased by $9.0 million during the year ended December 31, 2010 compared with the year ended December 31, 2009 due to an increase in the quarterly cash distribution rate per unit. BGH paid cash distributions of $49.8 million ($1.76 per unit) and $40.8 million ($1.44 per unit) during the years ended December 31, 2010 and 2009, respectively.

Distributions to noncontrolling partners of Buckeye, consisting primarily of distributions to holders of LP Units, increased by $15.6 million during the year ended December 31, 2010 due to an increase in the number of LP Units outstanding and an increase in the quarterly cash distribution rate per LP Unit. Buckeye paid cash distributions of $195.6 million ($3.825 per LP Unit) and $180.0 million ($3.625 per LP Unit) to its noncontrolling partners during the years ended December 31, 2010 and 2009, respectively.

We paid $16.4 million of costs associated with the Merger during the year ended December 31, 2010.

2009 Compared to 2008. Net cash flow provided by financing activities was $72.8 million for the year ended December 31, 2009 compared to $494.0 million for the year ended December 31, 2008. The following were the principal factors resulting in the $421.2 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 during the years ended December 31, 2009 and 2008, respectively. Repayments under the Services Company 3.60% ESOP Notes were $6.3 million and $6.3 million during the years ended December 31, 2009 and 2008, respectively. There were no borrowings or repayments under the BGH Credit Agreement in 2009 and 2008.

Net borrowings under the BES Credit Agreement were $143.8 million during the year ended December 31, 2009, while net repayments under the BES Credit Agreement (and its predecessor facility which was replaced in May 2008) were $4.0 million during the year ended December 31, 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 as discussed above. 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 2009 for the public issuance of 3.0 million LP Units as discussed above. In 2008, we received $113.1 million in net proceeds from the public issuance of 2.6 million LP Units.

We received $3.2 million and $0.3 million in net proceeds from the exercise of LP Unit options during the years ended December 31, 2009 and 2008, respectively.

Cash distributions paid to partners of BGH increased by $6.4 million during the year ended December 31, 2009 compared with the year ended December 31, 2008 due to an increase in the quarterly cash distribution rate per unit. BGH paid cash distributions of $40.8 million ($1.44 per unit) and $34.4 million ($1.215 per unit) during the years ended December 31, 2009 and 2008, respectively.

Distributions to noncontrolling partners of Buckeye increased by $20.7 million during the year ended December 31, 2009 due to an increase in the number of LP Units outstanding and an increase in the quarterly cash distribution rate per LP Unit. Buckeye paid cash distributions of $180.0 million ($3.625 per LP Unit) and $159.3 million ($3.425 per LP Unit) to its noncontrolling partners during the years ended December 31, 2009 and 2008, 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. Property, 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 December 31, 2010 and 2009, the net book value of our property, plant and equipment was $2.3 billion and $2.2 billion, respectively. Property, plant and equipment is generally recorded at its original acquisition cost and its carrying value accounted for approximately 64.5% of our consolidated assets at December 31, 2010. Depreciation expense was $54.7 million, $50.9 million and $47.4 million for the years ended December 31, 2010, 2009 and 2008, 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 $4.4 million and $5.4 million annually, respectively.

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 (i) estimated future expenditures related to environmental matters are subject to cost fluctuations and can change materially, (ii) unanticipated liabilities may arise in connection with environmental remediation projects and may impact cost estimates, and (iii) 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, 2010, 2009 and 2008, we incurred environmental expenses, net of insurance recoveries, of $8.5 million, $10.6 million and $10.1 million, respectively. At December 31, 2010 and 2009, we had accrued $30.8 million and $29.9 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 physical derivative contracts. See Note 16 in the Notes to Consolidated Financial Statements for further discussion. The Energy Services segment has elected fair value hedge accounting for most of its inventory of refined petroleum products; however the segment has not used hedge accounting with respect to its physical derivative contracts, or for the corresponding futures contracts that economically hedge those positions. In addition, hedge accounting has not been elected for financial instruments that have been executed to economically hedge a portion of the Energy Services segment s refined petroleum products held in inventory. The physical derivative contracts and futures contracts not accounted for as hedges are all marked-to-market on our consolidated balance sheet with gains and losses being recognized in earnings during the period. At December 31, 2010, we had approximately $2.4 million of net liabilities for physical derivative contracts in our consolidated financial statements. At December 31, 2010, the net fair value of the non-designated futures contracts is approximately $15.5 million and has been recognized as assets on our consolidated balance sheet. The futures contracts that have been designated as fair value hedges of refined petroleum inventory are marked-to-market on our consolidated balance sheet with gains and losses being recognized in earnings during the period. The underlying inventory hedged by these futures contracts is also adjusted to market on our consolidated balance sheet with gains and losses recognized in earnings during the period. The net fair value of the futures designated as fair value hedges is approximately $28.1 million at December 31, 2010 and has been recognized as a liability on our consolidated 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 physical derivative contracts represent Level 2 fair value measurements because their value is derived from similar contracts with similar delivery and settlement terms which are traded on established exchanges. We enter into physical fixed-price contracts for the procurement of future inventory and physical fixed-price sales contracts for customers electing to fix the price of their refined petroleum product needs. The fixed-price purchase contracts are typically executed with credit worthy counterparties and are short-term in nature, thus evaluated for credit risk in the same manner as the fixed price sales contracts. However, because the fixed-price 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, 2010, we had reduced the fair value of the fixed-price contracts by a $0.2 million credit valuation adjustment to reflect this counterparty credit risk. The delivery periods for the contracts range from one to ten months, with the substantial majority of deliveries concentrated in the first four months of 2011.

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Because little or no public credit information is available for the Energy Services segment s customers who have fixed-price 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. We continue to monitor and evaluate performance and collections with respect to these fixed-price 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: (i) discrete financial forecasts for the assets contained within the reporting unit, which rely on management s estimates of revenue, operating expenses and volumes; (ii) long-term growth rates for cash flows beyond the discrete forecast period; (iii) appropriate discount rates; and (iv) 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. Based upon our most recent goodwill impairment testing, each reporting unit s fair value was substantially in excess of its carrying value.

At December 31, 2010 and 2009, the carrying value of our goodwill was $432.1 million. We did not record any goodwill impairment charges during the years ended December 31, 2010, 2009 and 2008. For additional information regarding our goodwill, see Note 10 in the Notes to Consolidated Financial Statements.

In 2011, we acquired BORCO for approximately $1.7 billion in cash and equity (see Item 1, 2010 Developments for additional information regarding the acquisition). We expect to allocate a portion of the purchase price to goodwill, which could substantially increase our goodwill balance in the 2011 period.

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 flows 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, 2010 (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), (2)	$ 1,524,525	$ 1,525	$ 398,000	$ 275,000	$ 850,000
Interest payments (2), (3)	639,864	78,256	150,088	122,613	288,907
Operating leases: (4)					
Office space and other	17,930	2,042	3,075	3,285	9,528
Land leases (5)	307,738	3,117	6,806	7,224	290,591
Purchase obligations (6)	22,887	22,887			
Capital expenditure obligations (7)	2,032	2,032			
Total contractual obligations	$ 2,514,976	$ 109,859	$ 557,969	$ 408,122	$ 1,439,026

(1) We have long-term payment obligations under our Credit Facility, our underwritten publicly issued notes and the 3.60% ESOP 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, 2010 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) On January 13, 2011, we sold the 4.875% Notes, which are due in 2021, which would increase the Total and the More than 5 Years amounts by $650.0 million. Semi-annual interest payments on these 4.875% Notes are due commencing August 2011, which would increase the interest payments amounts presented for each category by $316.9 million, $15.8 million, $63.4 million, $63.4 million and $174.3 million, respectively.

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

(4) We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the table represent minimum lease payment obligations under our operating leases with terms in excess of one year for the periods indicated. Lease expense is charged to operating expenses on a straight line basis over

the period of expected benefit. Contingent rental payments are expensed as incurred. Total rental expense for the years ended December 31, 2010, 2009 and 2008 was $21.3 million, $21.2 million and $20.2 million, respectively.

(5) 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

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two consecutive years. Lease expense associated with these leases, which is being recognized on a straight line basis over 44 years, was $7.1 million for the year ended December 31, 2010, including $4.2 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.

(6) 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, 2010.

(7) 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 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, 2010, the ESOP was directly obligated to a third-party lender for $1.5 million with respect to 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, 2010, the value of the LP Units owned by Services Company was approximately $100.3 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.

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.

Market Risk Non-Trading Instruments

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

Commodity Risk

Natural Gas Storage

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

As of December 31, 2010, the Natural Gas Storage segment has recorded the following assets and liabilities related to its hub services agreements (in thousands):

	December 31, 2010
Assets:	
Hub service agreements	$ 34,471
Liabilities:	
Hub service agreements	(19,942)
Total	$ 14,529

Energy Services

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

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

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As of December 31, 2010, the Energy Services segment had derivative assets and liabilities as follows (in thousands):

	December 31, 2010
Assets:	
Physical derivative contracts	$ 1,522
Futures contracts for refined products	112
Liabilities:	
Physical derivative contracts	(3,900)
Futures contracts for refined products	(12,635)
Futures contracts for natural gas	(206)
Total	$ (15,107)

Our hedged inventory portfolio extends to the second quarter of 2011. The majority of the unrealized loss at December 31, 2010 for inventory hedges represented by futures contracts will be realized by the first quarter of 2011 as the related inventory is sold. During the year ended December 31, 2010, a loss of $2.0 million was recorded on inventory hedges that were ineffective, and a loss of $3.8 million was recorded in earnings related to the time value component of the derivative instruments fair value that was excluded from the assessment of hedge effectiveness. At December 31, 2010, open refined petroleum product derivative contracts varied in duration in the overall portfolio, but did not extend beyond October 2011. In addition, at December 31, 2010, we had refined petroleum product inventories that we intend to use to satisfy a portion of the physical derivative contracts.

Based on a hypothetical 10% movement in the underlying quoted market prices of the commodity financial instruments outstanding at December 31, 2010, the estimated fair value of the portfolio of commodity financial instruments would be as follows (in thousands):

Scenario	Resulting Classification	Commodity Financial Instrument Portfolio Fair Value
Fair value assuming no change in underlying commodity prices (as is)	Liability	$(15,107)
Fair value assuming 10% increase in underlying commodity prices	Liability	$(47,239)
Fair value assuming 10% decrease in underlying commodity prices	Asset	$ 17,024

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 contracts was based on observable market data related to the obligation to provide refined petroleum products to customers.

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

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Interest Rate Risk

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

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

At December 31, 2010, we had total fixed-rate debt obligations at face value of $1,426.5 million, consisting of $125.0 million of the 5.125% Notes, $275.0 million of the 5.300% Notes, $300.0 million of the 4.625% Notes, $150.0 million of the 6.750% Notes, $300.0 million of the 6.050% Notes, $275.0 million of the 5.500% Notes and the 3.60% ESOP Notes. The fair value of these fixed-rate debt obligations at December 31, 2010 was approximately $1,515.2 million. We estimate that a 1% decrease in rates for obligations of similar maturities would increase the fair value of our fixed-rate debt obligations by approximately $84.2 million.

At December 31, 2010, our variable-rate obligations were $98.0 million under the Credit Facility and $284.3 million under the BES Credit Agreement. Based on the balances outstanding at December 31, 2010, we estimate that a 1% increase or decrease in interest rates would increase or decrease annual interest expense by approximately $3.8 million.

We expect to issue new fixed-rate debt (i) on or before July 15, 2013 to repay the $300.0 million of 4.625% Notes that are due on July 15, 2013 and (ii) on or before October 15, 2014 to repay the $275.0 million of 5.300% Notes that are due on October 15, 2014, although no assurances can be given that the issuance of fixed-rate debt will be possible on acceptable terms. During 2009, we entered into four forward-starting interest rate swaps with a total aggregate notional amount of $200.0 million related to the anticipated issuance of debt on or before July 15, 2013 and three forward-starting interest rate swaps with a total aggregate notional amount of $150.0 million related to the anticipated issuance of debt on or before October 15, 2014. During the year ended December 31, 2010, we entered into two forward-starting interest rate swaps with a total aggregate notional amount of $100.0 million related to the anticipated issuance of debt on or before July 15, 2013 and three forward-starting interest rate swaps with a total aggregate notional amount of $125.0 million related to the anticipated issuance of debt on or before October 15, 2014. The purpose of these swaps is to hedge the variability of the forecasted interest payments on these expected debt issuances that may result from changes in the benchmark interest rate until the expected debt is issued. During the year ended December 31, 2010, unrealized losses of $13.3 million were recorded in accumulated other comprehensive income (loss) to reflect the change in the fair values of the forward-starting interest rate swaps. We designated the swap agreements as cash flow hedges at inception and expect the changes in values to be highly correlated with the changes in value of the underlying borrowings.

On January 13, 2011, we sold the 4.875% Notes in an underwritten public offering. The notes were issued at 99.62% of their principal amount. Total proceeds from this offering, after underwriters fees, expenses and debt issuance costs of $4.5 million, were approximately $643.0 million, and were used to fund a portion of the purchase price for our acquisition of BORCO (see Note 26 in the Notes to Consolidated Financial Statements). In December 2010, in connection with the proposed offering, we entered into a treasury lock agreement to fix the ten-year treasury rate at 3.3375% per annum on a notional amount of $650.0 million. In January 2011, we subsequently cash-settled the treasury lock agreement upon the issuance of the 4.875% Notes and received approximately $0.5

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million, which will be recognized as a reduction to interest and debt expense over the ten-year term of the 4.875% Notes.

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, 2010 (in thousands):

Scenario	Resulting Classification	Financial Instrument Portfolio Fair Value
Fair value assuming no change in underlying interest rates (as is)	Asset	$ 3,348
Fair value assuming 10% increase in underlying interest rates	Asset	$ 42,344
Fair value assuming 10% decrease in underlying interest rates	Liability	$(36,036)

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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, 2010. 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, 2010, 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 Chief Executive Officer	Keith E. St.Clair Chief Financial Officer

February 28, 2011

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, 2010, 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, 2010, 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, 2010 of Buckeye and our report dated February 28, 2011 expressed an unqualified opinion on those consolidated financial statements.

/s/ DELOITTE & TOUCHE LLP
Philadelphia, Pennsylvania
February 28, 2011

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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, 2010 and 2009, and the related consolidated statements of operations, comprehensive income, cash flows, and partners capital for each of the three years in the period ended December 31, 2010. 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

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, 2010, 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 28, 2011 expressed an unqualified opinion on Buckeye s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Philadelphia, Pennsylvania
February 28, 2011

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

	Year Ended December 31,		
	2010	**2009**	**2008**
Revenues:			
Product sales	$ 2,469,210	$ 1,125,653	$ 1,304,097
Transportation and other services	682,058	644,719	592,555
Total revenue	3,151,268	1,770,372	1,896,652
Costs and expenses:			
Cost of product sales and natural gas storage services	2,462,275	1,103,015	1,274,135
Operating expenses	278,245	275,930	281,965
Depreciation and amortization	59,590	54,699	50,834
Asset impairment expense		59,724	
General and administrative	50,599	41,147	43,226
Equity plan modification expense	21,058		
Reorganization expense		32,057	
Total costs and expenses	2,871,767	1,566,572	1,650,160
Operating income	279,501	203,800	246,492
Other income (expense):			
Earnings from equity investments	11,363	12,531	7,988
Interest and debt expense	(89,169)	(75,147)	(75,410)
Other income (expense)	(687)	453	1,553
Total other expense	(78,493)	(62,163)	(65,869)
Net income	201,008	141,637	180,623
Less: net income attributable to noncontrolling interests	(157,928)	(92,043)	(154,146)
Net income attributable to Buckeye Partners, L.P.	$ 43,080	$ 49,594	$ 26,477
Earnings per limited partner unit:			
Basic	$ 1.66	$ 2.49	$ 1.33
Diluted	$ 1.65	$ 2.49	$ 1.33
Weighted average number of limited partner units outstanding:			
Basic	26,016	19,952	19,952
Diluted	26,086	19,952	19,952

See Notes to Consolidated Financial Statements.

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

	Year Ended December 31,		
	2010	**2009**	**2008**
Net income	$ 201,008	$ 141,637	$ 180,623
Other comprehensive income (loss):			
Change in value of derivatives	(14,357)		
Amortization of interest rate swaps	964		
Amortization of benefit plan costs	(1,149)		
Adjustment to funded status of benefit plans	(5,870)		
Total other comprehensive loss	(20,412)		
Comprehensive income	$ 180,596	$ 141,637	$ 180,623

See Notes to Consolidated Financial Statements.

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

	December 31, 2010	December 31, 2009
Assets:		
Current assets:		
Cash and cash equivalents	$ 13,626	$ 37,574
Trade receivables, net	167,274	124,165
Construction and pipeline relocation receivables	6,803	14,095
Inventories	351,605	310,214
Derivative assets	1,634	4,959
Assets held for sale		22,000
Prepaid and other current assets	85,689	104,251
Total current assets	626,631	617,258
Property, plant and equipment, net	2,305,884	2,238,321
Equity investments	107,047	96,851
Goodwill	432,124	432,124
Intangible assets, net	44,067	45,157
Other non-current assets	58,463	56,860
Total assets	$ 3,574,216	$ 3,486,571
Liabilities and partners capital:		
Current liabilities:		
Line of credit	$ 284,300	$ 239,800
Current portion of long-term debt	1,525	6,178
Accounts payable	68,530	56,723
Derivative liabilities	17,285	14,665
Accrued and other current liabilities	144,880	113,474
Total current liabilities	516,520	430,840
Long-term debt	1,519,393	1,500,495
Other non-current liabilities	128,043	102,942
Total liabilities	2,163,956	2,034,277
Commitments and contingent liabilities		
Partners capital:		
Buckeye Partners, L.P. capital:		
General Partner (0 and 1,995 units outstanding as of December 31, 2010 and 2009, respectively)		7
Limited Partners (71,436,099 and 19,578,684 units outstanding as of December 31, 2010 and 2009, respectively)	1,413,664	236,545

Management (0 and 370,819 units outstanding as of December 31, 2010 and 2009, respectively)		3,225
Equity gains on issuance of Buckeye Partners, L.P. limited partner units		2,557
Accumulated other comprehensive loss	(21,259)	
Total Buckeye Partners, L.P. capital	1,392,405	242,334
Noncontrolling interests	17,855	1,209,960
Total partners capital	1,410,260	1,452,294
Total liabilities and partners capital	$ 3,574,216	$ 3,486,571

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,		
	2010	**2009**	**2008**
Cash flows from operating activities:			
Net income	$ 201,008	$ 141,637	$ 180,623
Adjustments to reconcile net income to net cash provided by operating activities:			
Value of ESOP shares released	4,745	1,641	2,202
Depreciation and amortization	59,590	54,699	50,834
Asset impairment expense		59,724	
Net changes in fair value of derivatives	(45,579)	20,531	(24,228)
Non-cash deferred lease expense	4,235	4,500	4,598
Earnings from equity investments	(11,363)	(12,531)	(7,988)
Distributions from equity investments	14,679	9,660	5,113
Equity plan modification expense	21,058		
Amortization of other non-cash items	5,720	8,257	4,643
Change in assets and liabilities, net of amounts related to acquisitions:			
Trade receivables	(43,109)	(44,112)	36,060
Construction and pipeline relocation receivables	7,292	7,406	(8,930)
Inventories	9,955	(177,309)	(4,362)
Prepaid and other current assets	16,368	(28,937)	(27,823)
Accounts payable	11,808	14,569	(10,647)
Accrued and other current liabilities	30,416	(1,296)	9,336
Other non-current assets	9,528	(9,916)	9,520
Other non-current liabilities	(3,872)	(861)	(10,394)
Total adjustments from operating activities	91,471	(93,975)	27,934
Net cash provided by operating activities	292,479	47,662	208,557
Cash flows from investing activities:			
Capital expenditures	(77,699)	(87,309)	(120,472)
Acquisition of additional interest in equity investment	(13,512)		
Contributions to equity investments		(3,870)	(9,880)
Acquisitions, net of cash acquired	(46,915)	(54,443)	(657,643)
Net proceeds (expenditures) for disposal of property, plant and equipment	23,938	1,419	(365)
Proceeds from the sale of Farm & Home retail operations			52,584
Net cash used in investing activities	(114,188)	(144,203)	(735,776)
Cash flows from financing activities:			
Net proceeds from issuance of limited partner units		104,632	113,111
Proceeds from exercise of unit options	4,789	3,204	316

Issuance of long-term debt		273,210	298,050
Repayment of long term-debt	(6,178)	(6,294)	(6,289)
Borrowings under credit facility	298,400	317,120	558,554
Repayments under credit facility	(278,400)	(537,387)	(260,288)
Net borrowings (repayments) under BES credit agreement	44,500	143,800	(4,000)
Debt issuance costs	(3,551)	(4,691)	(2,111)
Costs associated with agreement and plan of merger	(16,427)		
Distributions paid to noncontrolling partners of Buckeye Partners, L.P.	(195,564)	(180,008)	(159,306)
Settlement payment of interest rate swaps			(9,638)
Distributions paid to partners of Buckeye GP Holdings L.P.	(49,808)	(40,752)	(34,385)
Net cash provided by (used in) financing activities	(202,239)	72,834	494,014
Net decrease in cash and cash equivalents	(23,948)	(23,707)	(33,205)
Cash and cash equivalents Beginning of year	37,574	61,281	94,486
Cash and cash equivalents End of year	$ 13,626	$ 37,574	$ 61,281

See Notes to Consolidated Financial Statements.

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

	Buckeye Partners, L.P. Unitholders						
	General Partner	Limited Partners	Management Units	Equity Gains on Issuance of Buckeye s Limited Partner Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Partners capital January 1, 2008	$ 7	$ 232,928	$ 3,156	$ 2,239	$	$ 1,066,143	$ 1,304,473
Net income		25,981	496			154,146	180,623
Distributions paid to partners of BGH		(33,741)	(644)				(34,385)
Recognition of unit-based compensation charges		1,397	29				1,426
Equity gains on issuance of Buckeye s LP Units				212		(212)	
Net proceeds from issuance of Buckeye s LP Units						113,111	113,111
Amortization of Buckeye s unit-based compensation awards						486	486
Exercise of Buckeye s LP Unit options						316	316
Services Company s non-cash ESOP distributions						(5,685)	(5,685)
Acquired noncontrolling interests not previously owned						(1,537)	(1,537)
Distributions paid to noncontrolling interests						(159,306)	(159,306)
Other						(688)	(688)

Partners capital December 31, 2008	7	226,565	3,037	2,451	1,166,774	1,398,834
Net income		48,668	926		92,043	141,637
Distributions paid to partners of BGH		(39,990)	(762)			(40,752)
Recognition of unit-based compensation charges		1,302	24			1,326
Equity gains on issuance of Buckeye s LP Units				106	(106)	
Net proceeds from issuance of Buckeye s LP Units					104,632	104,632
Amortization of Buckeye s unit-based compensation awards					3,079	3,079
Exercise of Buckeye s LP Unit options					3,204	3,204
Services Company s non-cash ESOP distributions					(6,073)	(6,073)
Distributions paid to noncontrolling interests					(180,008)	(180,008)
Change in value of derivatives					17,722	17,722
Amortization of interest rate swaps					961	961
Other					7,732	7,732
Partners capital December 31, 2009	7	236,545	3,225	2,557	1,209,960	1,452,294
Net income		42,175	905		157,928	201,008
Costs associated with agreement and plan of merger		(6,750)	(128)		(9,549)	(16,427)
Distributions paid to partners of BGH		(48,877)	(931)			(49,808)
Recognition of unit-based compensation charges		21,916	419			22,335
Amortization of Buckeye s		2,163			6,040	8,203

unit-based compensation awards							
Exercise of Buckeye s LP Unit options		340				4,449	4,789
Services Company s non-cash ESOP distributions						(5,385)	(5,385)
Distributions paid to noncontrolling interests						(195,564)	(195,564)
Amortization of benefit plan costs					(132)	(1,017)	(1,149)
Adjustment to funded status of benefit plans					(5,870)		(5,870)
Change in value of derivatives					23,762	(38,119)	(14,357)
Amortization of interest rate swaps					109	855	964
Noncash accrual for distribution equivalent rights						(936)	(936)
Cancellation of 80,000 LP Units in connection with the Merger						3,132	3,132
Other						7,031	7,031
Effect of Merger on partners capital	(7)	1,166,152	(3,490)	(2,557)	(39,128)	(1,120,970)	
Partners capital December 31, 2010	$	$ 1,413,664	$	$	$ (21,259)	$ 17,855	$ 1,410,260

See Notes to Consolidated Financial Statements.

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

1. ORGANIZATION

Buckeye Partners, L.P. is a publicly traded Delaware master limited partnership (MLP), the limited partnership units representing limited partner interests (LP Units) of which are listed on the New York Stock Exchange (NYSE) under the ticker symbol BPL. Buckeye GP LLC (Buckeye GP) is our general partner. Buckeye GP is a wholly owned subsidiary of Buckeye GP Holdings L.P. (BGH), a Delaware limited partnership that was previously publicly traded on the NYSE prior to Buckeye s merger with BGH (see below for further information). 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.

We were formed in 1986 and own and operate one of the largest independent refined petroleum products pipeline systems in the United States in terms of volumes delivered with approximately 5,400 miles of pipeline and 69 active products terminals that provide aggregate storage capacity of over 53 million barrels. In 2011, we closed the acquisition of a Bahamian terminal facility with a total installed capacity of approximately 21.6 million barrels (see Note 26). In addition, we operate and maintain approximately 2,600 miles of other pipelines under agreements with major oil and gas, petrochemical and chemical companies, and perform certain engineering and construction management services for third parties. We also own and operate a major natural gas storage facility in northern California, and are a wholesale distributor of refined petroleum products in the United States in areas also served by our pipelines and terminals. We operate and report in five business segments: Pipeline Operations; Terminalling & Storage; Natural Gas Storage; Energy Services; and Development & Logistics. See Note 23 for a discussion of our business segments.

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

BGH is considered the surviving consolidated entity for accounting purposes, while Buckeye is the surviving consolidated entity for legal and reporting purposes. The Merger was accounted for as an equity transaction. Therefore, changes in BGH s ownership interest as a result of the Merger did not result in gain or loss recognition. See Note 2 for further information regarding financial statement presentation.

We incurred $16.4 million of costs associated with the Merger during the year ended December 31, 2010. We charged these costs directly to partners capital.

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, 2010, Services Company owned approximately 2.1% of our LP Units. Services Company employees provide services to our operating subsidiaries. Pursuant to a services agreement entered into in December 2004, our operating subsidiaries reimburse Services Company for the costs of the services provided by Services Company. 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, but, following completion of the Merger, BGH s obligation to make this payment was terminated. Services Company has been consolidated into our financial statements.

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

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

These consolidated financial statements were originally the financial statements of BGH prior to the effective date of the Merger. The Merger was accounted for as an equity transaction, and as such, changes in BGH s ownership interest as a result of the Merger did not result in gain or loss recognition. Under applicable accounting guidance, the exchange of BGH s units for our LP Units was accounted for as a BGH equity issuance and BGH was the surviving entity for accounting purposes. Although BGH was the surviving entity for accounting purposes, Buckeye was the surviving entity for legal purposes; consequently, the name on these financial statements was changed from Buckeye GP Holdings L.P. to Buckeye Partners, L.P.

The reconciliation of our net income, as historically reported, to the net income reported in these financial statements is as follows (in thousands):

	Year Ended December 31,	
	2009	2008
Net income, as previously reported	$ 146,900	$ 189,881
Adjustments:		
Depreciation and amortization (1)	4,465	4,465
Costs and expenses (2)	(9,108)	(11,594)
Other (3)	(620)	(2,129)
Net income	$ 141,637	$ 180,623

(1) Represents the amortization of the market value of LP Units issued in August 1997 in connection with the restructuring of Services Company s ESOP. The market value of those LP Units was $64.2 million, and this amount was recorded as a deferred charge and is being amortized on a straight-line basis over 13.5 years.

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

(3) Includes interest expense on Services Company s debt and commitment fees on BGH s credit facility. See Note 13 for further information.

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

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 include the accounts of our wholly-owned subsidiaries and the accounts of Services Company on a consolidated basis.

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

Business Segments

We operate and report in five business segments: Pipeline Operations; Terminalling & Storage; Natural Gas Storage; Energy Services; and Development & Logistics. 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, 2010, 2009 and 2008 was $2.5 million, $3.4 million and $2.3 million, respectively. The weighted average rates used to capitalize interest on borrowed funds was 4.8%, 5.4% and 5.4% for the years ended December 31, 2010, 2009 and 2008, respectively.

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 derivative instruments.

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

Comprehensive Income

Our comprehensive income is determined based on net income adjusted for changes in other comprehensive income 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. Prior to the Merger, our comprehensive income equaled our net income.

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 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 $21.6 million and $18.1 million at December 31, 2010 and 2009, respectively. We incurred approximately $3.6 million of debt issuance costs during the year ended December 31, 2010 primarily related to the amendment to the Buckeye Energy Services LLC (BES) credit agreement (see Note 13). Accumulated amortization was approximately $10.4 million and $7.0 million at December 31, 2010 and 2009, respectively.

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BUCKEYE PARTNERS, L.P.
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Derivative Instruments

We use derivative 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 derivative instrument contracts are recognized in the current period in earnings unless specific hedge accounting criteria are met. If the derivative 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 derivative 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 derivative 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 derivative 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 derivative instruments 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 derivative instruments 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 instrument is not highly effective as a hedge or that it has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively.

Earnings per LP Unit

Basic earnings per LP Unit is determined by dividing our net income, after deducting the amount allocated to noncontrolling interests, 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 LTIP) (see Note 22).

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

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

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

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, 2010 and 2009, our accrued liabilities for environmental remediation projects totaled $30.8 million and $29.9 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, 2010, 2009 or 2008.

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.

Fair Value

Cash and cash equivalents, trade receivables, net, 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 values of our fixed-rate debt were estimated by observing market trading prices and by comparing the historic market prices of our publicly-issued debt with the market prices of other MLPs publicly-issued debt with similar credit ratings and terms. The fair values of our variable-rate debt are their carrying amounts, as the carrying amount reasonably approximates fair value due to the variability of the interest rates. 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 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 contracts. See Note 16 for further discussion.

BUCKEYE PARTNERS, L.P.
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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 compared to its book value. If the fair value of the reporting unit exceeds its book value including associated goodwill amounts, the goodwill is considered to be unimpaired and no impairment charge is required. If the fair value of the reporting unit 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 U.S. federal and state income tax purposes, we and each of our subsidiaries, except for Buckeye Development & Logistics I, LLC (BDL), are not taxable entities. Accordingly, our taxable income, except for BDL, is generally includable in the U.S. federal and state income tax returns of our individual partners. Buckeye Caribbean Terminals Inc., which was converted to a limited liability company in 2011, is subject to income taxes within the Commonwealth of Puerto Rico.

Effective August 1, 2004, BDL 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 deferred tax liabilities of $0.2 million and $0.4 million as of December 31, 2010 and 2009, respectively, which are recorded in non-current liabilities. As of December 31, 2010 and 2009, our reported amount of net assets for GAAP purposes exceeded our tax basis for allocating taxable income under our partnership agreement.

Income taxes were benefits of $0.9 million and $0.3 million for the years ended December 31, 2010 and 2009, respectively. For the year ended December 31, 2008, income taxes were an expense of $0.8 million. Income tax benefit/expense is included in operating expenses in the consolidated statements of operations.

The Puerto Rican entity that we acquired is undergoing an audit of its Puerto Rico income tax returns for the tax years 2002 through 2005. In our purchase price allocation, we recorded a $17.7 million liability related to the uncertain outcome of the income tax audit with an offsetting indemnification asset from Shell for the same amount. See Note 4 for further discussion.

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. See Note 10 for further discussion.

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.

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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 weighted-average cost 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).

Net Income Allocation

For periods prior to the Merger, net income allocated to noncontrolling interests was determined by deducting Buckeye GP s allocated share of Buckeye s net income for the period from Buckeye s net income. Buckeye GP s allocated share of Buckeye s net income was determined by Buckeye s partnership agreement. Buckeye allocated net income to its limited partners and its general partner based upon their ownership interests in Buckeye. Buckeye first allocated net income to its 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 shared in the remaining income or loss based upon their proportionate interests in Buckeye. Following the Merger, we allocate a portion of our net income to noncontrolling interests related to Services Company and third-party owners of Sabina Pipeline (Sabina) and WesPac Pipelines Memphis LLC (WesPac Memphis) and a majority of our net income to our limited partners.

Noncontrolling Interests

The consolidated balance sheets include noncontrolling interests that relate primarily to the Services Company and the portions of Sabina and WesPac Memphis that are not owned by Buckeye. Similarly, the consolidated statements of operations include noncontrolling interests that reflect amounts not attributable to Buckeye. Prior to the Merger, noncontrolling interests reported by BGH also included equity interests in Buckeye that were not owned by BGH.

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.

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

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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 earnings. 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

Fair Value Measurements. In January 2010, the Financial Accounting Standards Board (FASB) issued guidance that requires new disclosures related to fair value measurements. The new guidance requires expanded disclosures related to transfers between Level 1 and 2 activities and a gross presentation for Level 3 activity. The new accounting guidance is effective for fiscal years and interim periods beginning after December 15, 2009, except for the new disclosures related to Level 3 activities, which are effective for fiscal years beginning after December 15, 2010 and for interim periods within those years. The new guidance became effective for us on January 1, 2010, except for the new disclosures related to Level 3 activities, which will be effective for us on January 1, 2011. We have included the enhanced disclosure requirements regarding fair value measurements in Note 16.

Health Care Reform Acts. In April 2010, the FASB issued guidance that addresses changes in accounting for income taxes resulting from the Health Care and Education Reconciliation Act of 2010 and the Patient Protection and Affordable Care Act. We adopted the new guidance as of its effective date, April 14, 2010. The adoption of this new guidance did not have a material impact on our consolidated financial statements.

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

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

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.

Revenue Recognition

Pipeline Operations segment. Revenues from pipeline tariffs and fees are associated with the transportation of refined petroleum products at published tariffs as well as revenues associated with line leases for committed capacity on a particular system that may or may not be utilized. Tariff revenues are recognized either at the point of delivery or at the point of receipt, pursuant to specifications outlined in the respective regulated and non-regulated tariffs. Revenues associated with line leases are recognized ratably over the respective lease terms, regardless of whether the capacity is actually utilized, and are subject to take or pay arrangements. All pipeline tariff and fee revenues are based on actual volumes and rates. As is common in the industry, our tariffs incorporate loss allocation or loss allowance factors that are intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value at the time the variance occurred, and the result is recorded as either an increase or decrease to transportation and other service revenues. In addition, we have certain agreements that require counterparties to ship a minimum volume over an agreed-upon period. Revenue pursuant to such agreements is recognized at the earlier of when the volume is shipped or when the counterparty s ability to make up the minimum volume has expired.

Terminalling & Storage segment. Revenues from terminalling, storage and rental operations are recognized as the services are performed. Storage and terminalling revenues include storage fees that are generated when we lease storage capacity and terminalling fees, or throughput fees, that are generated when we receive refined petroleum products from one connecting pipeline and redeliver such products to another connecting carrier or to customers through a truck-loading rack. We generate revenue through a combination of month-to-month and multi-year storage capacity leases and terminalling service arrangements. Storage fees resulting from short-term and long-term contracts are typically recognized in revenue ratably over the term of the contract, regardless of the actual storage capacity utilized. Terminalling fees are recognized as the refined petroleum product exits the terminal and is delivered to a connecting carrier, third-party terminal or a customer through a truck-loading rack. In addition, we have certain agreements that require counterparties to throughput a minimum volume over an agreed-upon period. Revenue pursuant to such agreements is recognized at the earlier of when the volume exits the terminal or when the counterparty s ability to make up the minimum volume has expired.

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

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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 at the time title to the product sold transfers to the purchaser, which occurs upon delivery of the product to the purchaser or its designee.

Development & 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. At December 31, 2010 and 2009, our allowance for doubtful accounts was $2.9 million and $1.5 million, respectively, and is included in trade receivables in our 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 we grant to customers. In addition, we 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, 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, 2010, 2009 and 2008, no customer contributed more than 10% of consolidated revenue.

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 & Storage, Natural Gas Storage and Development & Logistics segments bill on a monthly basis. We believe that these billing practices may reduce credit risk.

Unit-Based Compensation

BGH GP has an equity compensation plan (Equity Compensation Plan) for certain members of BGH GP s senior management, who also serve as our senior management. The Equity Compensation Plan included both time-based and performance-based participation in the equity of BGH GP (but not ours) referred to as override units. On December 31, 2010, the Equity Compensation Plan was modified, and as a result of the modification, we recognized a non-cash compensation charge of $21.1 million (see Note 18 for further information). We also award unit-based compensation to employees and directors primarily under the LTIP, which became effective in March 2009. We formerly awarded options to acquire LP Units to employees pursuant to the Buckeye Partners, L.P. Unit Option and

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Distribution Equivalent Plan (the Option Plan). 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 was 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: (i) termination benefits pursuant to voluntary and involuntary severance plans of $16.0 million; (ii) post-retirement benefits of $6.4 million (see Note 17); and (iii) other related costs of $9.7 million.

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

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

4. ACQUISITIONS AND DISPOSITIONS

Business Combinations

Our 2010 acquisitions of terminals from Chevron U.S.A. Inc. (Chevron) and an affiliate of Royal Dutch Shell plc (Shell), the 2009 acquisition of pipeline and terminal assets from ConocoPhillips and the 2008 acquisitions of Lodi Gas Storage, L.L.C. (Lodi Gas), Farm & Home Oil Company LLC (Farm & Home) and a terminal in Albany, New York (Albany Terminal) have been accounted for as business combinations. The total purchase price for these acquisitions was allocated to the fair value of the assets acquired and the liabilities assumed based on an assessment of their fair values at the acquisition date, with amounts exceeding the fair values being recorded as goodwill. 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.

In addition, the 2011 acquisition of Bahamas Oil Refining Company International Limited (BORCO) from affiliates of FRC Founders Corporation (First Reserve) and from Vopak Bahamas B.V. (Vopak) will also be accounted for as a business combination.

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Entry into Sale and Purchase Agreement to Acquire BORCO

On December 18, 2010, we entered into a sale and purchase agreement with First Reserve, pursuant to which we agreed to acquire First Reserve s indirect 80% interest in FR Borco Coop Holdings, L.P. (FRBCH), the indirect owner of BORCO, for approximately $1.4 billion of cash and equity. The transaction was completed in January 2011. We acquired the remaining 20% interest from Vopak in February 2011. See Note 26 for further information regarding the BORCO acquisition.

Opelousas Terminal Acquisition

On November 5, 2010, we acquired a refined petroleum products terminal in Opelousas, Louisiana from Chevron for $13.0 million in cash. The terminal, which is connected to Colonial Pipeline, currently supplies central Louisiana with branded gasoline, diesel and ethanol. The terminal includes seven storage tanks with approximately 135,000 barrels of total storage capacity and a truck rack. Chevron entered into a commercial contract with us concurrent with the acquisition regarding usage of the acquired facility. We believe the acquisition of these assets furthers our geographic diversification efforts and enables us to participate in a growth market outside our existing system footprint, creating synergies between our Terminalling & Storage segment and our Development & Logistics segment. The operations of these acquired assets are reported in the Terminalling & Storage segment. The purchase price has been allocated primarily to property, plant and equipment.

Puerto Rico Terminal Acquisition

On December 10, 2010, we acquired a refined petroleum products terminal in Yabucoa, Puerto Rico from Shell for $32.6 million, net of cash acquired of $3.5 million. The terminal includes 44 storage tanks with approximately 4.6 million barrels of gasoline, jet fuel, diesel, fuel oil and crude oil storage capacity. Shell entered into a commercial contract with us concurrent with the acquisition regarding usage of the acquired facility. We believe the acquisition of these assets furthers our geographic diversification efforts as this was our first acquisition outside the continental United States and enables us to participate in a growth market outside our existing system footprint. The operations of these acquired assets are reported in the Terminalling & Storage segment. The purchase price has been allocated to tangible and intangible assets acquired, on a preliminary basis, as follows (in thousands):

Current assets	$ 172
Inventory	867
Property, plant and equipment	31,770
Intangible assets	3,363
Other assets	17,720
Current liabilities	(3,591)
Other liabilities	(17,720)
Allocated purchase price	$ 32,581

The Puerto Rican entity that we acquired is undergoing an audit of its Puerto Rico income tax returns for the tax years 2002 through 2005. The Puerto Rico Treasury Department has notified the entity of certain areas for discussion but has not issued a preliminary or final notice of debt regarding such years. Pursuant to the purchase and sale agreement we entered into in connection with this acquisition, Shell has assumed the full responsibility, through an indemnity and hold harmless provision, for the payment of any income tax debt that may be assessed by the Puerto Rico Treasury Department under this audit. In the purchase price allocation above, we recorded a $17.7 million liability related to the uncertain outcome of the income tax audit with an offsetting indemnification asset from Shell for the same amount.

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Refined Petroleum Products Terminals and Pipeline Assets Acquisition

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

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

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 (ArcLight), which owns an indirect interest in BGH GP. The cost of Lodi Gas was approximately $442.4 million in cash and consisted of the following (in thousands):

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 total purchase price exceeded the fair value of the assets acquired and the liabilities assumed at the acquisition date. 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 (in thousands):

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

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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 total purchase price exceeded the fair value of the assets acquired and the liabilities assumed at the acquisition date. 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 (in thousands):

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

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. Revenues from the retail 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, BES, with BES continuing as the surviving entity of the merger.

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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 & 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 total purchase price exceeded the fair value of the assets acquired and the liabilities assumed at the acquisition date. The purchase price has been allocated to the tangible and intangible assets acquired, including goodwill, as follows (in thousands):

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 year ended December 31, 2008 assumes that the acquisitions of Lodi Gas, Farm & Home and the Albany Terminal occurred as of the beginning of 2008.

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The pro forma presentation below assumes that our equity offerings used in part to fund the acquisition of Lodi Gas occurred effective January 1, 2008. 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. 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 period presented or the results that may be attained in the future (in thousands):

	(Unaudited) Year Ended December 31, 2008
Revenues:	
As reported	$ 1,896,652
Pro forma adjustments	180,422
Pro forma revenues	$ 2,077,074
Net income:	
As reported	$ 180,623
Pro forma adjustments	768
Pro forma net income	$ 181,391
Pro forma earnings per LP Unit:	
Basic	$ 1.37
Diluted	$ 1.37
Pro forma weighted average number of LP Units outstanding: (1)	
Basic	19,952
Diluted	19,952

(1) Pro forma basic and diluted weighted average number of LP Units outstanding, which previously reflected historical BGH unit and per unit amounts, have been restated for the reverse unit split (see Note 2).

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 & Storage segment.

In August 2010, we acquired pipeline assets in western Pennsylvania for $1.3 million. These assets have been included in the Pipeline Operations segment.

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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 (in thousands):

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

Effective May 1, 2008, we purchased the 50% member interest in WesPac Pipelines San Diego LLC (WesPac San Diego) not already owned by us from Kealine LLC for $9.3 million. The operations of WesPac San Diego 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.

Acquisition of Additional Interest in West Shore Pipe Line Company

On August 2, 2010, in connection with our exercise of a right of first refusal, we completed the acquisition of additional shares of West Shore Pipe Line Company (West Shore) common stock from an affiliate of BP plc, resulting in an increase in our ownership interest in West Shore from 24.9% to 34.6%. We paid approximately $13.5 million for this additional interest. We exercised our right of first refusal to purchase the additional shares because of the favorable economics associated with the investment opportunity and our desire to increase our ownership in a successful joint venture pipeline that we currently operate.

Sale of Buckeye NGL Pipeline

Effective January 1, 2010, we sold our ownership interest in an approximately 350-mile natural gas liquids pipeline (the Buckeye NGL Pipeline) that runs from Wattenberg, Colorado to Bushton, Kansas for $22.0 million. See Note 8 for further discussion.

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.

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

In April 2010, PHMSA proposed penalties totaling approximately $0.5 million in connection with a tank overfill incident that occurred at our facility in East Chicago, Indiana, in May 2005 and other related personnel

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qualification issues raised as a result of PHMSA s 2008 Integrity Inspection. We are contesting the proposed penalty. The timing or outcome of this appeal cannot reasonably be determined at this time.

In January 2011, PHMSA issued us a final order with penalties totaling $0.2 million in connection with issues related to documentation, inspection and physical signage of certain of our pipelines raised as a result of PHMSA s 2005 2006 inspection of certain facilities in Illinois, Indiana, Ohio, and Michigan as well as compliance records.

In January 2011, PHMSA issued us a final order with penalties totaling $0.1 million in connection with an employee s failure to follow certain pipeline-marking procedures in connection with a product release that occurred in New York, New York in November 2009.

On July 30, 2010, a putative class action was filed by a unitholder against BGH, MainLine Management LLC (MainLine Management), BGH GP and each of MainLine Management s directors in the District Court of Harris County, Texas under the caption *Broadbased Equities v. Forrest E. Wylie, et. al.* In the Petition, the plaintiff alleged that MainLine Management and its directors breached their fiduciary duties to BGH s public unitholders by, among other things, acting to facilitate the sale of BGH to Buckeye in order to facilitate the gradual sale by BGH GP of its interest in BGH and failing to disclose all material facts in order that the BGH unitholders can cast an informed vote on the Merger Agreement. Among other things, the Petition sought an order certifying a class consisting of all BGH unitholders, a determination that the action is a proper derivative action, damages in an unspecified amount, and an award of attorneys fees and costs.

On August 2, 2010, a putative class action was filed by a unitholder against BGH, MainLine Management, Merger Sub, Buckeye, Buckeye GP and each of MainLine Management s directors in the District Court of Harris County, Texas under the caption *Henry James Steward v. Forrest E. Wylie, et. al.* In the Petition, the plaintiff alleged that MainLine Management and its directors breached their fiduciary duties to BGH s public unitholders by, among other things, failing to disclose all material facts in order that the BGH unitholders can cast an informed vote on the Merger Agreement. The Petition also alleged that Buckeye, Buckeye GP and Merger Sub aided and abetted the breaches of fiduciary duty. Among other things, the Petition sought an order certifying a plaintiff class consisting of all of BGH unitholders, an order enjoining the Merger, rescission of the Merger, damages in an unspecified amount, and an award of attorneys fees and costs.

On August 2, 2010, a putative class action was filed by a unitholder against BGH, MainLine Management, BGH GP, ArcLight, Kelso & Company (Kelso), Buckeye, Buckeye GP and each of MainLine Management s directors, in the District Court of Harris County, Texas under the caption *JR Garrett Trust v. Buckeye GP Holdings L.P. et al.* In the Petition, the plaintiff alleged that MainLine Management and its directors breached their fiduciary duties to BGH s public unitholders by, among other things, accepting insufficient consideration, failing to condition the Merger on a majority vote of public unitholders of BGH, and failing to disclose all material facts in order that the BGH unitholders can cast an informed vote on the Merger Agreement. The Petition also alleged that Buckeye, Buckeye GP, BGH GP, ArcLight and Kelso aided and abetted the breaches of fiduciary duty. Among other things, the Petition sought an order certifying a class consisting of all of BGH s unitholders, an order enjoining the Merger, damages in an unspecified amount, and an award of attorneys fees and costs.

On August 24, 2010, the District Court of Harris County, Texas, entered an order consolidating three previously filed putative class actions (*Broadbased Equities v. Forrest E. Wylie, et. al.*, *Henry James Steward v. Forrest E. Wylie, et. al.*, and *JR Garrett Trust v. Buckeye GP Holdings L.P., et al.,*) under the caption of *Broadbased Equities v. Forrest E. Wylie, et al.* and appointing interim co-lead class counsel and interim co-liaison counsel. The plaintiffs subsequently filed a consolidated amended class action and derivative complaint on September 1, 2010 (the Complaint). The Complaint purports to be a putative class and derivative action alleging that MainLine Management and its directors breached their fiduciary duties to BGH s public unitholders in connection with the Merger by, among other things, accepting insufficient consideration and failing to disclose all material facts in order that BGH s unitholders may cast an informed vote on the Merger Agreement, and that we, Buckeye GP, MainLine Management, Merger Sub, BGH GP, ArcLight and Kelso aided and abetted the breaches of fiduciary duty.

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On October 29, 2010, the parties to the litigation entered into a Memorandum of Understanding (MOU) in connection with a proposed settlement of the class action and the Complaint. The MOU provides for dismissal with prejudice of the litigation and a release of the defendants from all present and future claims asserted in the litigation in exchange for, among other things, the agreement of the defendants to amend the Merger Agreement to reduce the termination fees payable by BGH upon termination of the Merger Agreement and to provide BGH s unitholders with supplemental disclosure to BGH s and our joint proxy statement/prospectus, dated September 24, 2010. The supplemental disclosure is set forth in a joint proxy statement/prospectus supplement, dated October 29, 2010, which was filed with the SEC on November 1, 2010.

In addition, the MOU provides that, in settlement of the plaintiffs claims (including any claim against the defendants by the plaintiffs counsel for attorneys fees or expenses related to the litigation), the defendants (or their insurers) will pay a cash payment of $900,000, subject to final court approval of the settlement. On January 25, 2011, pursuant to the MOU, the parties signed a Stipulation of Settlement. The Stipulation of Settlement has not yet been filed with the court. The proposed settlement is subject to several conditions, including, without limitation, court approval. There is no assurance that the court will approve the settlement.

We and the other defendants vigorously deny all liability with respect to the facts and claims alleged in the Complaint, and specifically deny that any modifications to the Merger Agreement or any supplemental disclosure was required or advisable under any applicable rule, statute, regulation or law. However, to avoid the substantial burden, expense, risk, inconvenience and distraction of continuing the litigation, and to fully and finally resolve the claims alleged, we and the other defendants agreed to the proposed settlement described above.

Environmental Contingencies

In accordance with our accounting policy, we recorded operating expenses, net of insurance recoveries, of $8.5 million, $10.6 million and $10.1 million during the years ended December 31, 2010, 2009 and 2008, respectively, related to environmental expenditures unrelated to claims and proceedings.

Ammonia Contract Contingencies

On November 30, 2005, BDL (formerly Buckeye Gulf Coast Pipe Lines, L.P.) purchased an ammonia pipeline and other assets from El Paso Merchant Energy-Petroleum Company (EPME), a subsidiary of El Paso Corporation (El Paso). As part of the transaction, BDL assumed the obligations of EPME under several contracts involving monthly purchases and sales of ammonia. EPME and BDL agreed, however, that EPME would retain the economic risks and benefits associated with those contracts until their expiration at the end of 2012. To effectuate this agreement, BDL passes through to EPME both the cost of purchasing ammonia under a supply contract and the proceeds from selling ammonia under three sales contracts. For the vast majority of monthly periods since the closing of the pipeline acquisition, the pricing terms of the ammonia contracts have resulted in ammonia costs exceeding ammonia sales proceeds. The amount of the shortfall generally increases as the market price of ammonia increases.

EPME has informed BDL that, notwithstanding the parties agreement, it will not continue to pay BDL for shortfalls created by the pass-through of ammonia costs in excess of ammonia revenues. EPME encouraged BDL to seek payment by invoking a $40.0 million guaranty made by El Paso, which guaranteed EPME s obligations to BDL. If EPME fails to reimburse BDL for these shortfalls 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 BDL could adversely affect our financial position, results of operations and cash flows. To date, BDL has continued to receive payment for ammonia costs under the contracts at issue. BDL has not called on El Paso s guaranty and believes only BDL may invoke the guaranty. EPME, however, contends that El Paso s guaranty is the source of payment for the shortfalls, but has not clarified the extent to which it believes the guaranty has been exhausted. We have been working with EPME to terminate the ammonia sales contracts and ammonia supply contracts and, at no out of pocket cost to us, have terminated one of the ammonia sales contracts. Given, however, the uncertainty of future ammonia prices and EPME s future actions, we continue to believe we may have risk of

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loss and, at this time, are unable to estimate the amount of any such losses we might incur in the future. We are assessing our options in the event that we and EPME are unable to terminate the remaining contracts or otherwise mitigate the remaining risk, including potential recourse against EPME and El Paso, with respect to this matter.

Customer Bankruptcy

One of our customers filed for bankruptcy in October 2009 and approximately $4.1 million remained payable to us from the customer pursuant to a pre-bankruptcy contract. In June 2010, we entered into a court approved settlement with the bankrupt customer and its largest creditor pursuant to which we were to be paid at least $2.0 million in cash, and we were released from both asserted and unasserted claims. In August 2010, we received a settlement payment of $2.0 million. As a result of the settlement, our Development & Logistics segment recognized approximately $2.1 million in expense related to the write-off of a portion of the outstanding receivable balance during the year ended December 31, 2010.

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, 2010, 2009 and 2008 was $21.3 million, $21.2 million and $20.2 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 (in thousands):

	Office space and other (1)	**Land Leases** (2)	**Total**
2011	$ 2,042	$ 3,117	$ 5,159
2012	1,513	3,340	4,853
2013	1,562	3,466	5,028
2014	1,615	3,550	5,165
2015	1,670	3,674	5,344
Thereafter	9,528	290,591	300,119
Total	$ 17,930	$ 307,738	$ 325,668

(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, which is being recognized on a straight-line basis over 44 years, was approximately $7.1 million, $7.4 million and $7.1 million for the years ended December 31, 2010, 2009 and 2008, respectively. At December 31, 2010 and 2009, $4.2 million and $4.5 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.

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Leases Where We are Lessor

We have entered into capacity leases with remaining terms from 5 to 12 years that are accounted for as operating leases. All of the agreements provide for negotiated extensions. Future minimum lease payments to be received under such operating leasing arrangements as of December 31, 2010 are as follows (in thousands):

	Years Ending December 31,
2011	$ 13,581
2012	13,581
2013	13,581
2014	11,526
2015	11,152
Thereafter	50,890
Total	$ 114,311

6. INVENTORIES

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

	December 31, 2010	December 31, 2009
Refined petroleum products (1)	$ 340,659	$ 299,473
Materials and supplies	10,946	10,741
Total inventories	$ 351,605	$ 310,214

(1) Ending inventory was 134.9 million and 141.7 million gallons of refined petroleum products at December 31, 2010 and 2009, respectively.

At December 31, 2010 and 2009, approximately 94% and 99%, respectively, of our refined petroleum products inventory was hedged. Hedged inventory is valued at current market prices with the change in value of the inventory reflected in our consolidated statements of operations. Inventory not accounted for as a fair value hedge is accounted for at weighted average cost.

7. PREPAID AND OTHER CURRENT ASSETS

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

	December 31, 2010	December 31, 2009
Prepaid insurance	$ 8,865	$ 7,088
Insurance receivables	8,886	13,544
Ammonia receivable	1,295	7,429
Margin deposits	18,833	21,037

Prepaid services	24,359	21,571
Unbilled revenue	3,263	13,201
Tax receivable	120	7,162
Prepaid taxes	5,417	2,213
Other	14,651	11,006
Total prepaid and other current assets	$ 85,689	$ 104,251

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8. PROPERTY, PLANT AND EQUIPMENT

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

	December 31, 2010	December 31, 2009
Land	$ 64,905	$ 64,712
Rights-of-way	97,529	97,309
Pad gas	29,346	29,346
Buildings and leasehold improvements	109,585	103,535
Machinery, equipment and office furnishings	2,251,027	2,130,552
Construction in progress	66,642	78,363
Total property, plant and equipment	2,619,034	2,503,817
Less: Accumulated depreciation	(313,150)	(265,496)
Total property, plant and equipment, net	$ 2,305,884	$ 2,238,321

Depreciation expense was $54.7 million, $50.9 million and $47.4 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Impairment of Long-Lived Assets and Assets Held for Sale

We owned and operated 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 Buckeye s 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 (in thousands):

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 (in thousands):

ARO liability balance, January 1, 2009	$ 919
Accretion expense	101
ARO liability balance, December 31, 2009	1,020
Accretion expense	92
ARO liability balance, December 31, 2010 (1)	$ 1,112

(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 (in thousands):

		December 31,	
	Ownership (1)	2010	2009
Muskegon Pipeline LLC	40.0%	$ 14,552	$ 15,273
Transport4, LLC	25.0%	341	379
West Shore (2)	34.6%	43,563	30,320
West Texas LPG Pipeline Limited Partnership	20.0%	48,591	50,879
Total equity investments		$ 107,047	$ 96,851

(1) Represents ownership interest in equity investment at December 31, 2010.

(2) See Note 4 for a discussion of the acquisition of an additional interest in West Shore.

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

	Year Ended December 31,		
	2010	2009	2008
Muskegon Pipeline LLC	$ 1,482	$ 1,437	$ 1,367
Transport4, LLC	162	147	70
West Shore	4,988	4,809	3,133
West Texas LPG Pipeline Limited Partnership	4,731	6,138	3,418
Total earnings from equity investments	$ 11,363	$ 12,531	$ 7,988

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Combined balance sheet data as of the dates indicated and income statement data for the periods indicated for our equity method investments are summarized below (in thousands):

	December 31, 2010	December 31, 2009
BALANCE SHEET DATA:		
Current assets	$ 30,905	$ 43,154
Noncurrent assets	206,076	204,843
Total assets	$ 236,981	$ 247,997
Current liabilities	$ 34,825	$ 32,592
Other liabilities	9,111	10,922
Combined equity	193,045	204,483
Total liabilities and combined equity	$ 236,981	$ 247,997

	Year Ended December 31, 2010	2009	2008
INCOME STATEMENT DATA:			
Revenues	$ 139,355	$ 134,786	$ 127,885
Costs and expenses	79,584	67,694	86,273
Non-operating expense	12,290	12,914	9,036
Net income	47,481	54,178	32,576

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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; it is subject to annual impairment testing. The following table summarizes our goodwill amounts by segment at the dates indicated (in thousands):

	December 31, 2010	December 31, 2009
Pipeline Operations:		
Purchase of general partner interests in 2004	$ 198,632	$ 198,632
Terminalling & Storage:		
Acquisition of six terminals in June 2000	11,355	11,355
Purchase of general partner interests in 2004	11,434	11,434
Acquisition of Albany Terminal in 2008	26,829	26,829
Subtotal	49,618	49,618
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
Development & Logistics:		
Purchase of general partner interests in 2004	13,182	13,182
Total goodwill	$ 432,124	$ 432,124

Intangible Assets

Intangible assets include customer relationships and contracts. These intangible assets have definite lives and are being amortized on a straight-line basis over their estimated useful lives ranging from 5 to 25 years. Our amortizable customer contracts are contracts that were acquired in connection with the acquisition of BDL in March 1999, the acquisition of the Taylor, Michigan terminal in December 2005, the acquisition of certain pipeline and terminal assets from ConocoPhillips in November 2009 and the acquisition of a terminal from Shell in 2010. 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 and 5 years in the case of the terminal acquisition from Shell. 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 (in thousands):

	December 31, 2010	December 31, 2009
Customer relationships	$ 41,663	$ 38,300
Accumulated amortization	(8,600)	(5,631)
Net carrying amount	33,063	32,669

Customer contracts	16,380	16,380
Accumulated amortization	(5,376)	(3,892)
Net carrying amount	11,004	12,488
Total intangible assets	$ 44,067	$ 45,157

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For the years ended December 31, 2010, 2009 and 2008, amortization expense related to intangible assets was $4.5 million, $3.5 million and $3.2 million, respectively. Amortization expense related to intangible assets is expected to be approximately $5.1 million for 2011, $5.1 million for 2012, $5.1 million for 2013, $4.9 million for 2014 and $4.0 million for 2015.

11. OTHER NON-CURRENT ASSETS

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

	December 31, 2010	December 31, 2009
Prepaid services	$ 5,836	$ 11,640
Unbilled revenue	2,163	
Derivative assets	3,892	17,204
Debt issuance costs	11,184	11,058
Insurance receivables	8,826	7,265
Indemnification asset (see Note 4)	17,720	
Other	8,842	9,693
Total other non-current assets	$ 58,463	$ 56,860

12. ACCRUED AND OTHER CURRENT LIABILITIES

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

	December 31, 2010	December 31, 2009
Taxes other than income	$ 20,698	$ 15,487
Accrued employee benefit liability	3,817	3,287
Environmental liabilities	10,471	10,799
Interest payable	30,700	30,613
Payable for ammonia purchase	2,354	7,015
Unearned revenue	18,776	6,829
Compensation and vacation	13,134	11,385
Accrued capital expenditures	2,032	1,611
Reorganization		2,133
Deferred consideration	2,010	1,675
Customer deposits	5,389	2,518
Other	35,499	20,122
Total accrued and other current liabilities	$ 144,880	$ 113,474

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13. DEBT OBLIGATIONS

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

	December 31, 2010	December 31, 2009
BGH:		
BGH Credit Agreement (1)	$	
Services Company:		
3.60% ESOP Notes due March 28, 2011	1,531	7,790
Retirement premium	(6)	(87)
Buckeye:		
4.625% Notes due July 15, 2013 (2)	300,000	300,000
5.300% Notes due October 15, 2014 (2)	275,000	275,000
5.125% Notes due July 1, 2017 (2)	125,000	125,000
6.050% Notes due January 15, 2018 (2)	300,000	300,000
5.500% Notes due August 15, 2019 (2)	275,000	275,000
6.750% Notes due August 15, 2033 (2)	150,000	150,000
Credit Facility	98,000	78,000
BES Credit Agreement	284,300	239,800
Total debt	1,808,825	1,750,503
Other, including unamortized discounts and fair value hedges	(3,607)	(4,030)
Subtotal debt	1,805,218	1,746,473
Less: current portion of long-term debt	(285,825)	(245,978)
Total long-term debt	$ 1,519,393	$ 1,500,495

(1) On November 19, 2010, in conjunction with the Merger, the BGH Credit Agreement was terminated.

(2) 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 (in thousands):

	Years Ending December 31,
2011	$ 285,825
2012	98,000
2013	300,000
2014	275,000
2015	
Thereafter	850,000

Total	$	1,808,825

The fair values of our aggregate debt and credit facilities were estimated to be $1,897.5 million and $1,769.8 million at December 31, 2010 and 2009, respectively.

Notes Offerings

On January 13, 2011, we sold $650.0 million aggregate principal amount of 4.875% Notes due 2021 (the 4.875% Notes) in an underwritten public offering. The notes were issued at 99.62% of their principal amount.

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Total proceeds from this offering, after underwriters fees, expenses and debt issuance costs of $4.5 million, were approximately $643.0 million, and were used to fund a portion of the purchase price for our acquisition of BORCO (see Note 26 for further discussion of the BORCO acquisition). In connection with this offering, we settled a treasury lock agreement, which resulted in the receipt of a settlement of $0.5 million, which will be amortized as a reduction to interest expense over the ten-year term of the 4.875% Notes (see Note 16).

On August 18, 2009, we sold $275.0 million aggregate principal amount of 5.500% Notes due 2019 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 (see below) and for working capital purposes.

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.

Bridge Loans

In December 2010, in connection with the proposed BORCO acquisition, we obtained a commitment from Barclays Bank and SunTrust Bank for senior unsecured bridge loans in an aggregate amount up to $595 million (or up to $775 million in the event we purchased both First Reserve s 80% interest and Vopak s 20% interest in FRBCH) (the Bridge Loans). The commitment was to expire upon the earliest to occur of the termination date as defined in the BORCO sale and purchase agreement, the consummation of the BORCO acquisition, the termination of the BORCO sale and purchase agreement or 120 days after December 18, 2010. We recognized approximately $2.0 million of commitments fees, which are included in interest and debt expense, related to the Bridge Loans. In January 2011, we terminated the Bridge Loans upon issuance of the 4.875% Notes. See Note 26 for further information.

BGH

BGH had a five-year, $10.0 million unsecured revolving credit facility with SunTrust Bank, as both administrative agent and lender (the BGH Credit Agreement). The BGH Credit Agreement may have been used for working capital and other partnership purposes. BGH had pledged all of the limited liability company interests in Buckeye GP as security for its obligations under the BGH Credit Agreement. Borrowings under the BGH Credit Agreement bore interest under one of two rate options, selected by BGH, equal to either (i) the greater of (a) the federal funds rate plus 0.5% and (b) SunTrust Bank s prime commercial lending rate; or (ii) the London Interbank Offered Rate (LIBOR), plus a margin which could have ranged from 0.40% to 1.40%, based on the ratings assigned by Standard & Poor s Rating Services and Moody s Investor Service to its senior unsecured non-credit enhanced long-term debt. BGH did not have amounts outstanding under the BGH Credit Agreement at December 31, 2009. The BGH Credit Agreement was terminated under the terms of the Merger Agreement. See Note 1 for further information regarding the Merger.

Services Company ESOP Notes

Services Company had total debt outstanding of $1.5 million and $7.7 million at December 31, 2010 and 2009, respectively, consisting of 3.60% Senior Secured Notes (the 3.60% ESOP Notes) due March 28, 2011 payable by the ESOP to a third-party lender. The 3.60% ESOP Notes were issued on May 4, 2004. The 3.60% ESOP Notes are collateralized by Services Company s common stock and are guaranteed by Services Company. In addition, we have committed that, in the event that the value of our LP Units owned by Services Company falls below 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 our LP Units owned by Services Company and the escrow account) up to

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the 125% minimum. Amounts deposited in the escrow account are returned to us when the value of our LP Units owned by Services Company s returns to an amount that exceeds the 125% minimum. At December 31, 2010, the value of our LP Units owned by Services Company was approximately $100.3 million, which exceeded the 125% requirement.

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) LIBOR plus an applicable margin. The applicable margin is determined based on the current utilization level of the Credit Facility and ratings assigned by Standard & Poor s Rating Services and Moody s Investor Service for our senior unsecured non-credit enhanced long-term debt. At December 31, 2010 and 2009, $98.0 million and $78.0 million, respectively, were outstanding under the Credit Facility. The weighted average interest rate for borrowings outstanding under the Credit Facility was 0.6% at December 31, 2010.

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, 2010, our Funded Debt Ratio was approximately 3.9 to 1.00. As permitted by the Credit Facility, the $284.3 million of borrowings by BES under its separate credit agreement (discussed below) was 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, 2010, 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, 2010 and 2009, we had committed $1.4 million in support of letters of credit. The obligations for letters of credit are not reflected as debt on our consolidated balance sheets.

BES Credit Agreement

BES had a credit agreement (the BES Credit Agreement) that provided for borrowings of up to $250.0 million with a maturity date of May 20, 2011. On June 25, 2010, BES amended and restated the BES Credit Agreement to increase the total commitments for borrowings available to BES up to $500.0 million and extend the maturity date to June 25, 2013. However, the maximum amount available to be borrowed under the amended and restated BES Credit Agreement is initially limited to $350.0 million. An accordion feature provides BES the ability to increase the commitments under the BES Credit Agreement to $500.0 million, subject to obtaining the requisite lender commitments and satisfying other customary conditions. In addition to the accordion, subject to BES s satisfaction of certain financial covenants as set forth in the financial covenants table below, BES may, from time to time, elect

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to increase or decrease the maximum amount available for borrowing under the BES Credit Agreement in $5.0 million increments, but in no event below $150.0 million or above $500.0 million. BES incurred $3.3 million of debt issuance costs related to the amendment, which is being amortized into interest expense over the term of the BES Credit Agreement.

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

The balances outstanding under the BES Credit Agreement were approximately $284.3 million and $239.8 million at December 31, 2010 and 2009, respectively, both of which were classified as current liabilities in our consolidated balance sheets due to the borrowing terms set forth in the BES Credit Agreement. The BES Credit Agreement requires BES to meet certain financial covenants, which are defined in the BES Credit Agreement and summarized below (in millions, except for the leverage ratio):

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

At December 31, 2010, BES s Consolidated Tangible Net Worth and Consolidated Net Working Capital were $121.3 million and $72.3 million, respectively, and the Consolidated Leverage Ratio was 3.4 to 1.0. The weighted average interest rate for borrowings outstanding under the BES Credit Agreement was 2.5% at December 31, 2010.

In addition, the BES Credit Agreement contains other covenants, including, but not limited to, covenants limiting BES s ability to incur additional indebtedness, to create or incur certain liens on its property, to consolidate, merge or transfer its assets, to make dividends or distributions, to dispose of its property, to make investments, to modify its risk management policy, or to engage in business activities materially different from those presently conducted. At December 31, 2010, we were not aware of any instances of noncompliance with the covenants under the BES Credit Agreement.

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14. OTHER NON-CURRENT LIABILITIES

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

	December 31, 2010	December 31, 2009
Accrued employee benefit liabilities (see Note 17)	$ 49,170	$ 45,837
Accrued environmental liabilities	20,346	19,053
Deferred consideration	16,415	18,425
Deferred rent	13,393	9,158
Uncertain tax position liability (see Note 4)	17,720	
Other	10,999	10,469
Total other non-current liabilities	$ 128,043	$ 102,942

15. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	December 31, 2010	December 31, 2009
Adjustments to funded status of retirement income guarantee plan and retiree medical plan	$ (10,323)	$
Amortization of interest rate swap	(6,789)	
Derivative instruments	3,144	
Accumulated amortization of retirement income guarantee plan and retiree medical plan	(7,291)	
Total accumulated other comprehensive loss (1)	$ (21,259)	$

(1) For periods prior to the Merger, amounts related to AOCI were included in noncontrolling interests.

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 and physical 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 physical 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.

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Interest Rate Derivatives

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

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

We expect to issue new fixed-rate debt (i) on or before July 15, 2013 to repay the $300.0 million of 4.625% Notes that are due on July 15, 2013 and (ii) on or before October 15, 2014 to repay the $275.0 million of 5.300% Notes that are due on October 15, 2014, although no assurances can be given that the issuance of fixed-rate debt will be possible on acceptable terms. During 2009, we entered into four forward-starting interest rate swaps with a total aggregate notional amount of $200.0 million related to the anticipated issuance of debt on or before July 15, 2013 and three forward-starting interest rate swaps with a total aggregate notional amount of $150.0 million related to the anticipated issuance of debt on or before October 15, 2014. During 2010, we entered into two forward-starting interest rate swaps with a total aggregate notional amount of $100.0 million related to the anticipated issuance of debt on or before July 15, 2013 and three forward-starting interest rate swaps with a total aggregate notional amount of $125.0 million related to the anticipated issuance of debt on or before October 15, 2014. The purpose of these swaps is to hedge the variability of the forecasted interest payments on these expected debt issuances that may result from changes in the benchmark interest rate until the expected debt is issued. During the years ended December 31, 2010 and 2009, unrealized losses of $13.3 million and unrealized gains of $17.2 million, respectively, were recorded in AOCI to reflect the change in the fair values of the forward-starting interest rate swaps. We designated the swap agreements as cash flow hedges at inception and expect the changes in values to be highly correlated with the changes in value of the underlying borrowings.

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

On January 13, 2011, we sold the 4.875% Notes in an underwritten public offering. The notes were issued at 99.62% of their principal amount. Total proceeds from this offering, after underwriters fees, expenses and debt issuance costs of $4.5 million, were approximately $643.0 million, and were used to fund a portion of the purchase price for our acquisition of BORCO (see Note 26). In December 2010, in connection with the proposed offering, we entered into a treasury lock agreement to fix the ten-year treasury rate at 3.3375% per annum on a notional amount of $650.0 million. In January 2011, we subsequently cash-settled the treasury lock agreement upon the issuance of the 4.875% Notes and received approximately $0.5 million, which will be recognized as a reduction to interest expense over the ten-year term of the 4.875% Notes.

Commodity Derivatives

Our Energy Services segment primarily uses exchange-traded refined petroleum product futures contracts to manage the risk of market price volatility on its refined petroleum product inventories and its physical commodity forward fixed-price purchase and sales contracts. The derivative contracts used to hedge refined petroleum product

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inventories are primarily 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. The fair values of futures contracts for inventory designated as hedging instruments in the following tables have been presented net of these offsetting futures contracts.

Our Energy Services segment has not used hedge accounting with respect to its physical derivative contracts. Therefore, our physical derivative contracts and the related futures contracts used to offset the changes in fair value of the fixed-price contracts are all marked-to-market on the consolidated balance sheets with gains and losses being recognized in earnings during the period. In addition, futures contracts were executed to economically hedge a portion of the Energy Services segment s refined petroleum products held in inventory. The mark-to-market is recorded on the consolidated balance sheet with gains and losses being recognized in earnings during the period.

In order to hedge the cost of natural gas used to operate our turbine engines at our Linden, New Jersey location, our Pipeline Operations segment bought natural gas futures contracts in March 2009 with terms that coincide with the remaining term of an ongoing natural gas supply contract (through July 2011). We designated the futures contract as a cash flow hedge at inception.

The following table summarizes our commodity derivative instruments outstanding at December 31, 2010 (amounts in thousands of gallons, except as noted):

	Volume (1)		**Accounting**
Derivative Purpose	**Current**	**Long-Term**	**Treatment**
<u>Derivatives NOT designated as hedging instruments:</u>			
Physical derivative contracts	4,444		Mark-to-market
Futures contracts for refined products	21,492		Mark-to-market
<u>Derivatives designated as hedging instruments:</u>			
Futures contracts for refined products	126,882		Fair Value Hedge
Futures contracts for natural gas (BBtu) (2)	210		Cash Flow Hedge

(1) Volume represents absolute value of net notional volume position.

(2) BBtu represents one billion British thermal units.

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

	December 31, 2010				
	Derivatives NOT Designated as Hedging Instruments	Derivatives Designated as Hedging Instruments	Derivative Net Carrying Value	Netting Balance Sheet Adjustment	Total
Physical derivative contracts	$ 1,552	$	$ 1,552	$ (30)	$ 1,522
Futures contracts for refined products	36,916		36,916	(36,804)	112
Total current derivative assets	38,468		38,468	(36,834)	1,634
Interest rate contracts		5,351	5,351	(1,459)	3,892
Total long-term derivative assets		5,351	5,351	(1,459)	3,892
Physical derivative contracts	(3,930)		(3,930)	30	(3,900)
Futures contracts for refined products	(21,368)	(28,071)	(49,439)	36,804	(12,635)
Futures contract for natural gas		(206)	(206)		(206)
Interest rate contracts		(2,003)	(2,003)	1,459	(544)
Total current derivative liabilities	(25,298)	(30,280)	(55,578)	38,293	(17,285)
Net derivative assets/(liabilities)	$ 13,170	$ (24,929)	$ (11,759)	$	$ (11,759)

	December 31, 2009				
	Derivatives NOT Designated as Hedging Instruments	Derivatives Designated as Hedging Instruments	Derivative Net Carrying Value	Netting Balance Sheet Adjustment	Total
Physical derivative contracts	$ 4,959	$	$ 4,959	$	$ 4,959
Futures contracts for refined products	7,594	1,992	9,586	(9,586)	
Futures contract for natural gas		312	312	(312)	
Total current derivative assets	12,553	2,304	14,857	(9,898)	4,959

Interest rate contracts		17,204	17,204		17,204
Total long-term derivative assets		17,204	17,204		17,204
Physical derivative contracts	(3,662)		(3,662)		(3,662)
Futures contracts for refined products	(384)	(20,517)	(20,901)	9,586	(11,315)
Futures contract for natural gas				312	312
Total current derivative liabilities	(4,046)	(20,517)	(24,563)	9,898	(14,665)
Net derivative assets/(liabilities)	$ 8,507	$ (1,009)	$ 7,498	$	$ 7,498

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

	December 31, 2010	December 31, 2009
Derivative assets	$ 1,634	$ 4,959
Other non-current assets	3,892	17,204
Derivative liabilities	(17,285)	(14,665)
Total	$ (11,759)	$ 7,498

Our hedged inventory portfolio extends to the second quarter of 2011. The majority of the unrealized loss of $28.1 million at December 31, 2010 for inventory hedges represented by futures contracts will be realized by the first quarter of 2011 as the related inventory is sold. A loss of $2.0 million and a gain of $2.6 million were recorded on inventory hedges that were ineffective for the years ended December 31, 2010 and 2009, respectively. The time value component of the derivative instrument s fair value was excluded from our hedge assessment and a loss of $3.8 million and a gain of $12.7 million was recorded during the years ended December 31, 2010 and 2009, respectively. At December 31, 2010, open refined petroleum product derivative contracts varied in duration in the overall portfolio, but did not extend beyond October 2011. In addition, at December 31, 2010, we had refined petroleum product inventories that we intend to use to satisfy a portion of the physical derivative contracts.

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

Derivatives NOT designated as hedging instruments:	Location	Gain (Loss) Recognized in Income on Derivatives Year Ended December 31, 2010	2009
Physical derivative contracts	Product sales	$ 3,032	$ (6,881)
Futures contracts for refined products	Cost of product sales and natural gas storage services	22,073	15,653
<u>Derivatives designated as fair value hedging instruments:</u>			
Futures contracts for refined products	Cost of product sales and natural gas storage services	$ (61,235)	$ (47,012)

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

Derivatives designated as cash flow hedging instruments:	Location	Gain (Loss) Reclassified From AOCI to Income (1) Year Ended December 31, 2010	2009
Futures contracts for natural gas	Cost of product sales and natural gas storage services	$(428)	$ (462)
Futures contracts for refined products	Cost of product sales and natural gas storage services		(146)
Interest rate contracts	Interest and debt expense	(964)	(1,240)

(1) For periods prior to the Merger, amounts related to AOCI were included in noncontrolling interests.

Derivatives designated as cash flow hedging instruments:	Change in Value Recognized in OCI on Derivatives Year Ended December 31, 2010	2009
Futures contracts for natural gas	$ (929)	$ (164)
Interest rate contracts	(13,856)	16,999

Fair Value Measurements

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

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

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

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

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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, 2010 and 2009, and the basis for that measurement, by level within the fair value hierarchy (in thousands):

	December 31,			
	2010		2009	
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)
Financial assets:				
Physical derivative contracts	$	$ 1,522	$	$ 4,959
Futures contracts for refined products	112			
Futures contracts for natural gas			312	
Asset held in trust			1,793	
Interest rate derivatives		3,892		17,204
Financial liabilities:				
Physical derivative contracts		(3,900)		(3,662)
Futures contracts for refined products	(12,635)		(11,315)	
Futures contracts for natural gas	(206)			
Interest rate derivatives		(544)		

Fair value	$ (12,729)	$ 970	$ (9,210)	$ 18,501

The values of the Level 1 derivative assets and liabilities were based on quoted market prices obtained from the NYMEX. The value of the Level 1 asset held in trust was obtained from quoted market prices.

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

The values of the Level 2 physical derivative contracts assets and liabilities were calculated using market approaches based on observable market data inputs, including published commodity pricing data, which is verified against other available market data, and market interest rate and volatility data. Level 2 physical derivative contract assets are net of credit value adjustments (CVA) determined using an expected cash flow model, which incorporates assumptions about the credit risk of the physical derivative contracts based on the historical and expected payment history of each customer, the amount of product contracted for under the agreement and the customer s historical and expected purchase performance under each contract. The Energy Services segment determined CVA is appropriate because few of the Energy Services segment s customers entering into these physical derivative contracts are large organizations with nationally-recognized credit ratings. The Level 2 physical derivative contracts assets of $1.5 million and $5.0 million as of December 31, 2010 and 2009, respectively, are net of CVA of ($0.2) million and ($0.9) million, respectively.

Non-Recurring

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

	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 plant, property and equipment included in assets held for sale at December 31, 2009 (see Note 4).

As a result of a loss in the customer base utilizing the Buckeye 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.

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

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 workplace 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 (in thousands):

	RIGP Year Ended December 31,		Retiree Medical Plan Year Ended December 31,	
	2010	**2009**	**2010**	**2009**
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 19,103	$ 27,134	$ 35,449	$ 34,877
Service cost	263	495	295	339
Interest cost	906	1,182	1,982	1,941
Plan participants contributions			397	295
Part D reimbursement				245
Actuarial loss (gain)	1,281	4,399	4,490	(964)
Curtailments				1,091
Settlements		(13,977)		
Benefit payments	(3,594)	(130)	(2,778)	(2,375)
Benefit obligation at end of year	$ 17,959	$ 19,103	$ 39,835	$ 35,449
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 5,427	$ 10,433	$	$
Actual return on plan assets	244	(358)		
Plan participants contributions			397	295
Part D reimbursement				245
Employer contribution	2,730	9,459	2,381	1,835
Settlements		(13,977)		
Benefits paid	(3,594)	(130)	(2,778)	(2,375)
Fair value of plan assets at end of year	$ 4,807	$ 5,427	$	$
Funded status at end of year	$ (13,152)	$ (13,676)	$ (39,835)	$ (35,449)

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

	RIGP December 31, 2010	RIGP December 31, 2009	Retiree Medical Plan December 31, 2010	Retiree Medical Plan December 31, 2009
Liabilities:				
Accrued employee benefit liabilities current	$	$	$ 3,817	$ 3,287
Accrued employee benefit liabilities noncurrent	$ 13,152	$ 13,676	$ 36,018	$ 32,162
AOCI: (1)				
Net actuarial loss	$ 9,829	$ 9,416	$ 15,103	$ 11,508
Prior service credit		(46)	(7,318)	(10,283)
Total	$ 9,829	$ 9,370	$ 7,785	$ 1,225

(1) For periods prior to the Merger, amounts related to AOCI were included in noncontrolling interests.

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

	RIGP December 31, 2010	RIGP December 31, 2009
Projected benefit obligation	$17,959	$19,103
Accumulated benefit obligation	11,119	13,156
Fair value of plan assets	4,807	5,427

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

	RIGP Year Ended December 31, 2010	RIGP 2009	RIGP 2008	Retiree Medical Plan Year Ended December 31, 2010	Retiree Medical Plan 2009	Retiree Medical Plan 2008
Weighted average expense assumptions:						
Discount rate	5.3%	5.5%	5.5%	5.8%	5.8%	5.8%
Expected return on plan assets	6.0%	7.5%	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 at the dates indicated:

	RIGP December 31, 2010	RIGP December 31, 2009	Retiree Medical Plan December 31, 2010	Retiree Medical Plan December 31, 2009

Weighted average balance sheet assumptions:				
Discount rate	4.7%	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 capita cost of covered health care benefits as of December 31, 2010 in the Retiree Medical Plan was 8.5% for 2011, 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 2010 results:

	1% Increase	1% (Decrease)
Effect on total service cost and interest cost components	$ 121	$ (107)
Effect on postretirement benefit obligation	1,585	(1,419)

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 (in thousands):

	RIGP Year Ended December 31,			Retiree Medical Plan Year Ended December 31,		
	2010	2009	2008	2010	2009	2008
Components of net periodic benefit cost:						
Service cost	$ 263	$ 495	$ 723	$ 294	$ 339	$ 382
Interest cost	907	1,182	1,018	1,982	1,941	1,947
Expected return on plan assets	(344)	(570)	(1,030)			
Recognized gain due to curtailments					(749)	
Amortization of prior service cost benefit	(46)	(485)	(454)	(2,964)	(3,240)	(3,438)
Actuarial loss due to settlements		7,280	1,371			
Amortization of unrecognized losses	967	1,069	296	894	1,016	1,023
Net periodic benefit costs	$ 1,747	$ 8,971	$ 1,924	$ 206	$ (693)	$ (86)
Other changes in plan assets and benefit obligations recognized in OCI:						
Net actuarial loss (gain)	$ 1,380	$ 5,328	$ 9,517	$ 4,490	$ 875	(2,669)
Amortization of net actuarial gain	(967)	(1,069)	(296)	(894)	(1,016)	(1,023)
Actuarial loss due to settlements		(7,280)	(1,371)			
Amortization of prior service cost	46	485	454	2,964	3,240	3,438
Total recognized in OCI	$ 459	$ (2,536)	$ 8,304	$ 6,560	$ 3,099	$ (254)

Total recognized in net period benefit cost and OCI	$ 2,206	$ 6,435	$ 10,228	$ 6,766	$ 2,406	$ (340)

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During the year ended December 31, 2011, we expect that the following amounts currently included in OCI will be recognized in our consolidated statement of operations (in thousands):

	RIGP	Retiree Medical Plan
Amortization of unrecognized losses	$1,080	$ 1,151
Amortization of prior service cost benefit		(2,964)

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

	RIGP	Retiree Medical Plan
2011	$2,198	$ 3,913
2012	1,568	3,023
2013	1,405	3,111
2014	1,415	3,129
2015	1,667	3,185
Thereafter	8,680	15,000

A minimum funding contribution is not required to be made to the RIGP during 2011. 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 the dates indicated (in thousands):

	December 31,			
	2010		2009	
	Quoted Prices in Active Markets (Level 1)	Unobservable Inputs (Level 3)	Quoted Prices in Active Markets (Level 1)	Unobservable Inputs (Level 3)
Mutual fund equity securities (1)	$ 609	$	$ 1,701	$
Mutual fund money market	760		162	
Coal lease (2)		3,438		3,564
Fair value of plan assets	$ 1,369	$ 3,438	$ 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 for the periods indicated (in thousands):

	Year Ended December 31, 2010	Year Ended December 31, 2009
Beginning balance, January 1	$ 3,564	$ 4,365
Lease payments received	392	381
Unrealized loss	(126)	(801)
Transfers out of Level 3	(392)	(381)
Ending balance, December 31	$ 3,438	$ 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 5% (or 6% if an employee has over 20 years of service) 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 $6.0 million, $7.1 million and $5.6 million during the years ended December 31, 2010, 2009 and 2008, 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, $0.3 million and $0.2 million during the years ended December 31, 2010, 2009 and 2008, 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 $0.3 million, $0.2 million and $0.2 million during the years ended December 31, 2010, 2009 and 2008, respectively.

18. UNIT-BASED COMPENSATION PLANS

BGH GP has an Equity Compensation Plan for certain members of BGH GP s senior management, who also serve as our senior management. Compensation expense recorded with respect to the override units, prior to the modification discussed below, was $1.2 million, $1.3 million and $1.4 million for the years ended December 31, 2010, 2009 and 2008, respectively. On December 31, 2010, BGH GP modified the override unit plan, which resulted in the recognition of $21.1 million of additional compensation expense.

We award unit-based compensation to employees and directors primarily under the LTIP, which became effective in March 2009. We formerly awarded options to acquire LP Units to employees pursuant to the Option Plan. We recognized compensation expense related to the LTIP and the Option Plan of $7.7 million, $3.1 million

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and $0.5 million for the years ended December 31, 2010, 2009 and 2008, respectively. These compensation plans are discussed below.

Management Units

Prior to BGH s initial public offering of its common units (the IPO) on August 9, 2006, our general partner was owned by MainLine, L.P. (MainLine), a privately held limited partnership. In May 2004, MainLine instituted a Unit Compensation Plan and issued 16,216,668 Class B Units to certain members of senior management.

Coincident with BGH s IPO on August 9, 2006, the equity interests of MainLine were exchanged for BGH s equity interests. The Class B Units of MainLine were exchanged for 1,362,000 of BGH s management units. Pursuant to the terms of the exchange, 70%, or 953,400 management units, became vested immediately upon their exchange, and the remaining 30%, or 408,600 of the management units, were subject to vesting over a three year period. However, coincident with the sale of Carlyle/Riverstone BPL Holdings II, L.P. s interests in BGH in June of 2007, all the remaining unvested management units immediately vested and were expensed. There were no additional management units available for issue.

We recognized deferred compensation in 2006 for the management units for which both (i) vesting was accelerated compared to the MainLine Class B Units, and (ii) were now deemed probable of vesting compared to our previous estimates. We determined that these criteria applied to 272,400 management units, the market value of which was $17.00 per unit or approximately $4.6 million in total at August 9, 2006. Of the total equity compensation charge of $4.6 million, we expensed approximately $3.5 million in 2006. The balance of $1.1 million was recorded as compensation expense in the first half of 2007. In connection with the Merger, the outstanding management units were converted into common units and then exchanged for LP Units using a ratio of 0.705 LP Units per common unit. At December 31, 2010, no management units were outstanding.

BGH GP s Override Units

Effective on June 25, 2007, BGH GP instituted an Equity Compensation Plan for certain members of BGH GP s senior management. This Equity Compensation Plan included both time-based and performance-based participation in the equity of BGH GP (but not ours) referred to as override units. We were required to reflect, as compensation expense and a corresponding contribution to Unitholders equity, the fair value of the compensation. We are not the sponsor of this plan and have no obligations with respect to it. Compensation expense recorded with respect to the override units, prior to the modification, was $1.2 million, $1.3 million and $1.4 million for the years ended December 31, 2010, 2009 and 2008, respectively. On December 31, 2010, BGH GP modified the override unit plan, which resulted in the recognition of $21.1 million of additional compensation expense.

The override units consisted of three equal tranches of units consisting of: Value A Units, Value B Units and Operating Units. The Operating Units vested over four years semi-annually beginning with a one-year cliff. The Value A Units generally vested based on the occurrence of an exit event as discussed below, an investment return of 2.0 times the original investment and an internal rate of return of at least 10%. The Value B Units generally vest based on the occurrence of an exit event, an investment return of 3.5 times the original investment and an internal rate of return of at least 10% or on a pro-rata basis on an investment return ranging from 2.0 to 3.5 times the original investment and an internal rate of return of at least 10%.

The above-noted exit event is generally defined as 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.

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

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In general, the override units are subject to forfeiture if a grantee resigns or is terminated for cause. Under certain conditions, as declared by the Board of BGH GP, grantees can receive interim distributions on the override units.

On December 31, 2010, the override unit plan was modified. All outstanding unvested Value A and Operating Units were immediately vested and those vested units were exchanged for LP Units. The vesting terms of the Value B Units remained unchanged. As a result of the modification, we recognized $21.1 million of additional compensation expense during the year ended December 31, 2010 related to the Value A and Operating Units. The equity plan modification expense related to the Operating Units was measured as the sum of the remaining unamortized compensation expense based on the grant-date fair values and the incremental value of the LP Units received over the calculated fair value of the Operating Units immediately prior to the modification. The fair value of the Operating Units immediately prior to the modification was calculated using a Monte Carlo simulation method that incorporated the market-based vesting condition that existed prior to the modification. The Monte Carlo simulation is a procedure to estimate the future equity value from the time of the valuation date to the exit event. The assumptions used for this estimate include an equity value of BGH GP of $822.2 million, an expected life of 1 year, a risk-free interest rate of 0.29%, volatility of 25% and dividends of zero. The equity plan modification expense related to the Value A Units was measured as the fair value of the LP Units received in exchange.

The following is a summary of the activity of the override units (in thousands) and the weighted average fair value per unit granted for the periods indicated. There were no override units granted during the year ended December 31, 2010.

	Number of Override Units			
	Value A Units	Value B Units	Operating Units	Total Number of Units Awarded
Unvested at January 1, 2009	1,763	1,763	1,245	4,771
Granted in 2009	212	212	212	636
Vested in 2009			(422)	(422)
Forfeited in 2009	(276)	(276)	(223)	(775)
Unvested at December 31, 2009	1,699	1,699	812	4,210
Vested in 2010 (1)	(1,699)		(812)	(2,511)
Unvested at December 31, 2010		1,699		1,699

	Value A	Value B	Operating
2009 Weighted average fair value per unit granted	$2.33	$1.60	$3.34
2008 Weighted average fair value per unit granted	2.11	1.43	2.98

(1) On December 31, 2010, all outstanding unvested Value A Units and Operating Units vested immediately. Vested override units were then exchanged for LP Units. Value B Units remained outstanding.

The vesting of the Value B Units is contingent on a performance condition, namely the completion of the exit event discussed above, an investment return of 3.5 times the original investment and an internal rate of return of at least 10% or on a pro-rata basis on an investment return ranging from 2.0 to 3.5 times the original investment and an internal rate of return of at least 10%. Accordingly, no compensation expense for the Value B Units will be recorded until an exit event and other requirements to vest occur.

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

	Year Ended December 31,	
	2009	2008
Current equity value (in millions)	$439.06	$439.02
Expected life in years	3.4	4.8
Risk-free interest rate	1.8%	3.0%
Volatility	0.45	0.35

LTIP

On March 20, 2009, the LTIP became effective. The 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.

The LTIP provides for the issuance of up to 1,500,000 LP Units, 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 LTIP. Persons eligible to receive grants under the 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. Phantom units or performance units may be granted to participants at any time as determined by the Compensation Committee. After giving effect to the issuance or forfeiture of phantom unit and performance unit awards through December 31, 2010, awards representing a total of 1,115,926 additional LP Units could be issued under the LTIP.

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 are expected to 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. Depending on the estimated probability of attainment of those performance goals, the compensation expense recognized related to the awards could increase or decrease over the remaining vesting period. Quarterly distributions related to DERs associated with phantom and performance 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 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, 2010 and 2009, eligible employees were allowed to defer up to 50% of their 2010 and 2009 compensation award under our Annual Incentive Compensation Plan or other discretionary bonus program in exchange for grants of phantom units equal in value to the amount of their cash award deferral (each such unit, a Deferral Unit). Participants also receive one matching phantom unit for each Deferral Unit. Approximately $1.8 million of 2009 compensation awards had been deferred at December 31, 2009, for which 62,332 phantom units

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(including matching units) were granted during 2010. These 2010 grants are included as granted in the LTIP activity table below. Approximately $1.6 million of 2010 compensation awards had been deferred at December 31, 2010 for which phantom units will be granted in 2011.

Awards under the LTIP

During the year ended December 31, 2010, the Compensation Committee granted 123,998 phantom units to employees (including the 62,332 phantom units granted pursuant to the Deferral Plan discussed above), 12,000 phantom units to independent directors of Buckeye GP and MainLine Management, and 123,338 performance units to employees. 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 by us throughout such 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 $0.6 million and $0.1 million for the years ended December 31, 2010 and 2009, respectively. 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.

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

	Number of LP Units	Weighted Average Grant Date Fair Value per LP Unit (1)	Total Value
Unvested at January 1, 2010	140,095	$ 39.81	$ 5,577
Granted	259,336	56.26	14,590
Vested	(18,642)	39.20	(731)
Forfeited	(15,876)	49.50	(786)
Unvested at December 31, 2010	364,913	$ 51.11	$ 18,650

(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, 2010, approximately $10.0 million of compensation expense related to the LTIP is expected to be recognized over a weighted average period of approximately 1.7 years.

Unit Option and Distribution Equivalent 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 2011, 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, 2010 is based upon options ultimately expected to vest. Forfeitures have been estimated at the time of grant and will be revised, if necessary, in

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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 Internal Revenue Service regulations. This modification did not have a material impact on our financial results. Following the adoption of the LTIP on March 20, 2009, we ceased making additional grants under the Option Plan.

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

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

The expected dividend yield 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. 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 or 2010.

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

	Number of LP Units	Weighted-Average Strike Price ($/LP Unit)	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (1)
Outstanding at January 1, 2010	349,400	$ 46.25		
Exercised	(107,900)	44.41		
Forfeited, cancelled or expired	300	58.96		
Outstanding at December 31, 2010	241,800	47.04	5.8	$ 4,785
Exercisable at December 31, 2010	142,000	$ 45.97	4.8	$ 2,962

(1) Aggregate intrinsic value reflects fully vested LP Unit options at the date indicated. Intrinsic value is determined by calculating the difference between our closing LP Unit price on the last trading day in 2010 and the exercise price, multiplied by the number of exercisable, in-the-money options.

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The total intrinsic value of options exercised during the years ended December 31, 2010, 2009 and 2008 was $1.7 million, $0.5 million and $0.1 million, respectively. At December 31, 2010, total unrecognized compensation cost related to unvested options was minimal. We expect to recognize this cost over a weighted average period of 0.2 years. At December 31, 2010, 333,000 LP Units were available for grant in connection with the Option Plan. However, with the adoption and utilization of the LTIP, we do not expect to make any future grants pursuant to the Option Plan. The fair value of options vested was $0.4 million, $0.4 million and $0.2 million during the years ended December 31, 2010, 2009 and 2008, respectively.

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, 2010, the ESOP was directly obligated to a third-party lender for $1.5 million with respect to the 3.60% ESOP Notes. See Note 13 for further information.

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. Total ESOP related costs charged to earnings were $5.0 million, $2.5 million and $3.4 million for the years ended December 31, 2010, 2009 and 2008, respectively.

20. RELATED PARTY TRANSACTIONS

We are managed by Buckeye GP, our general partner. Services Company is considered a related party with respect to us. As discussed in Note 2, our consolidated financial statements include the accounts of Services Company on a consolidated basis, and all intercompany transactions have been eliminated.

Services Company, which is beneficially owned by the ESOP, owned 1.5 million of our LP Units (approximately 2.1% of our LP Units outstanding) as of December 31, 2010. Distributions received by Services Company from us on such LP Units are used to fund obligations of the ESOP. Distributions paid to Services Company totaled $5.9 million, $7.2 million and $7.4 million for the years ended December 31, 2010, 2009 and 2008, respectively. Total distributions paid to Services Company decrease over time as Services Company sells LP Units to fund benefits payable to ESOP participants who exit the ESOP.

We incurred a senior administrative charge for certain management services performed by affiliates of Buckeye GP of $0.5 million and $1.9 million for the years ended December 31, 2009 and 2008, 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 or during the year ended December 31, 2010.

Prior to the Merger, Buckeye GP received incentive distributions from us pursuant to our partnership agreement and incentive compensation agreement. Incentive distributions were based on the level of quarterly cash distributions paid per LP Unit. Incentive distribution payments totaled $51.0 million, $45.7 million and $38.9 million during the years ended December 31, 2010, 2009 and 2008, 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.

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Two of MainLine Management 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.

On August 18, 2010, we and our general partner entered into the Merger Agreement with BGH, its general partner and Merger Sub, our subsidiary. On November 19, 2010, we consummated the Merger Agreement with our general partner, BGH, BGH s general partner, BGH GP, and Merger Sub. See Note 1 for further information regarding the Merger.

21. PARTNERS CAPITAL AND DISTRIBUTIONS

Our LP Units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights and privileges available to them under our partnership agreement. 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. In conjunction with the Merger, our partnership agreement was amended. See Note 1 for further information.

Summary of Changes in Outstanding Units

The following is a reconciliation of BGH s common units and management units and the conversion to Buckeye s LP Units outstanding for the periods indicated:

	General Partner	Limited Partners	Management Units	Total (1)
Units outstanding on January 1, 2008	2,830	27,766,817	530,353	28,300,000
Issuance of common units				
Units outstanding at December 31, 2008	2,830	27,766,817	530,353	28,300,000
Conversion of management units to common units		4,396	(4,396)	
Units outstanding at December 31, 2009	2,830	27,771,213	525,957	28,300,000
Cancellation of BGH units in connection with Merger (2)	(2,830)	(27,771,213)	(525,957)	(28,300,000)
Buckeye LP Units issued to BGH unitholders (2)		19,951,498		19,951,498
Buckeye LP Units outstanding on date of Merger		51,556,716		51,556,716
Cancellation of LP Units in connection with Merger (3)		(80,000)		(80,000)
LP Units issued pursuant to the LTIP		85		85
LP Units issued pursuant to the Option Plan		7,800		7,800
Units outstanding at December 31, 2010		71,436,099		71,436,099

(1) Amounts presented through the date of the Merger represent historical BGH units outstanding.

(2) On November 19, 2010, in connection with the Merger, BGH units outstanding were converted into LP Units at a ratio of 0.705 to 1.0. Buckeye issued approximately 20.0 million LP Units to BGH s unitholders. On November 19, 2010, Buckeye had approximately 51.6 million LP Units outstanding.

(3) In connection with the Merger, 80,000 LP Units held by BGH were cancelled.

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Cash Distributions

We generally make quarterly cash distributions to unitholders. Cash distributions paid to Unitholders of Buckeye for the years ended December 31, 2010, 2009 and 2008 were as follows (in thousands, except per LP Unit amounts):

Record Date	Payment Date	Amount Per LP Unit	Limited Partners	General Partner (1)	Total Cash Distributions
February 5, 2008	February 29, 2008	$ 0.8375	$ 38,289	$ 9,130	$ 47,419
May 9, 2008	May 30, 2008	0.8500	41,113	9,939	51,052
August 8, 2008	August 29, 2008	0.8625	41,721	10,200	51,921
November 7, 2008	November 28, 2008	0.8750	42,326	10,461	52,787
Total			$ 163,449	$ 39,730	$ 203,179
February 12, 2009	February 27, 2009	$ 0.8875	$ 42,930	$ 10,721	$ 53,651
May 11, 2009	May 29, 2009	0.9000	46,227	11,686	57,913
August 7, 2009	August 31, 2009	0.9125	46,877	11,965	58,842
November 12, 2009	November 30, 2009	0.9250	47,719	12,251	59,970
Total			$ 183,753	$ 46,623	$ 230,376
February 16, 2010	February 26, 2010	$ 0.9375	$ 48,425	$ 12,543	$ 60,968
May 17, 2010	May 28, 2010	0.9500	49,048	12,835	61,883
August 16, 2010	August 31, 2010	0.9625	49,778	13,121	62,899
November 15, 2010	November 30, 2010	0.9750	50,432	13,402	63,834
Total			$ 197,683	$ 51,901	$ 249,584

(1) Includes amounts paid to our general partner for its incentive distribution rights.

Cash distributions paid to unitholders of BGH for the years ended December 31, 2010, 2009 and 2008 were as follows (in thousands, except per unit amounts):

Record Date	Payment Date	Amount Per unit	Total Cash Distributions
February 5, 2008	February 29, 2008	$ 0.285	$ 8,066
May 9, 2008	May 30, 2008	0.300	8,490

August 8, 2008	August 29, 2008		0.310		8,773
November 7, 2008	November 28, 2008		0.320		9,056
Total				$	34,385
February 12, 2009	February 27, 2009	$	0.330	$	9,339
May 11, 2009	May 29, 2009		0.350		9,905
August 7, 2009	August 31, 2009		0.370		10,472
November 12, 2009	November 30, 2009		0.390		11,036
Total				$	40,752
February 16, 2010	February 26, 2010	$	0.410	$	11,603
May 17, 2010	May 28, 2010		0.430		12,169
August 16, 2010	August 31, 2010		0.450		12,735
November 15, 2010	November 30, 2010		0.470		13,301
Total				$	49,808

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On February 11, 2011, we announced a quarterly distribution of $0.9875 per LP Unit that is payable on February 28, 2011, to Unitholders of record on February 21, 2011. Total cash distributed to Unitholders on February 28, 2011 will be approximately $79.3 million.

22. EARNINGS PER LIMITED PARTNER UNIT

Basic and diluted earnings per LP unit is calculated by dividing net income, after deducting the amount allocated to noncontrolling interests, by the weighted-average number of LP units outstanding during the period.

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

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

	Year Ended December 31,		
	2010	**2009**	**2008**
Net income attributable to Buckeye Partners, L.P.	$ 43,080	$ 49,594	$ 26,477
Basic:			
Weighted average LP Units outstanding	25,627	19,578	19,578
Weighted average management units outstanding	389	374	374
Weighted average LP Units outstanding basic	26,016	19,952	19,952
Earnings per LP Unit basic	$ 1.66	$ 2.49	$ 1.33
Diluted:			
Weighted average LP Units outstanding basic	26,016	19,952	19,952
Dilutive effect of LP Unit options and LTIP awards granted	70		
Weighted average LP Units outstanding diluted	26,086	19,952	19,952
Earnings per LP Unit diluted	$ 1.65	$ 2.49	$ 1.33

23. BUSINESS SEGMENTS

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

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 & Storage

The Terminalling & Storage segment provides bulk storage and terminal throughput services. Through December 31, 2010, this segment had 59 refined petroleum products terminals in 11 states and one refined products terminal in Puerto Rico with aggregate storage capacity of approximately 30.4 million barrels. See Note 26 for a discussion of the BORCO acquisition, which added one terminal with an aggregate storage capacity of approximately 21.6 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 currently has 29 Bcf of working natural gas storage capacity 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 & Logistics

The Development & Logistics segment consists primarily of our contract operation of approximately 2,600 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 & Logistics segment also includes our ownership and operation of an ammonia pipeline and our majority ownership of Sabina, located in Texas.

Adjusted EBITDA

Adjusted EBITDA is the primary measure used by senior management, including our Chief Executive Officer, to evaluate our operating results and to allocate our resources. We define EBITDA, a measure not defined under GAAP, as net income attributable to our unitholders before interest and debt expense, income taxes and depreciation and amortization. EBITDA should not be considered an alternative to net income, operating income, cash flow from operations or any other measure of financial performance or liquidity presented in accordance with GAAP. The EBITDA measure eliminates the significant level of non-cash depreciation and amortization expense that results from the capital-intensive nature of our businesses and from intangible assets recognized in business combinations. In addition, EBITDA is unaffected by our capital structure due to the elimination of interest and debt expense and income taxes. We define Adjusted EBITDA, which is also a non-GAAP measure, as EBITDA plus: (i) non-cash deferred lease expense, which is the difference between the estimated annual land lease expense for our natural gas storage facility in the Natural Gas Storage segment to be recorded under GAAP and the actual cash to be paid for such annual land lease, (ii) non-cash unit-based compensation expense, (iii) the 2009 non-cash impairment expense of $59.7 million related to the Buckeye NGL Pipeline that we sold in January 2010, (iv) the 2009 expense of $32.1 million for organizational restructuring, (v) the 2010 non-cash BGH GP equity plan modification expense of $21.1 million and (vi) income attributable to noncontrolling interests related to Buckeye for periods prior to the Merger in order to provide consistency and comparability between periods before and after the Merger.

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

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unitholders, and these items may be defined differently by other companies. Our senior management uses Adjusted EBITDA to evaluate consolidated operating performance and the operating performance of our business segments and to allocate resources and capital to the business segments. In addition, our senior management uses Adjusted EBITDA as a performance measure to evaluate the viability of proposed projects and to determine overall rates of return on alternative investment opportunities.

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

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 or in Puerto Rico.

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

	Year Ended December 31,		
	2010	**2009**	**2008**
Revenue:			
Pipeline Operations	$ 400,926	$ 392,667	$ 387,267
Terminalling & Storage	175,000	136,576	119,155
Natural Gas Storage	95,337	99,163	61,791
Energy Services	2,481,566	1,125,013	1,295,925
Development & Logistics	37,696	34,136	43,498
Intersegment	(39,257)	(17,183)	(10,984)
Total revenue	$ 3,151,268	$ 1,770,372	$ 1,896,652
Operating income (loss):			
Pipeline Operations	$ 171,595	$ 93,957	$ 149,349
Terminalling & Storage	89,933	61,084	52,133
Natural Gas Storage	16,069	30,574	32,235
Energy Services	(1,367)	13,086	5,905
Development & Logistics	3,271	5,099	6,870
Total operating income	$ 279,501	$ 203,800	$ 246,492
Depreciation and amortization:			
Pipeline Operations	$ 36,799	$ 35,533	$ 35,188
Terminalling & Storage	9,521	7,258	6,051
Natural Gas Storage	6,594	5,971	4,599
Energy Services	4,933	4,204	3,386
Development & Logistics	1,743	1,733	1,610
Total depreciation and amortization	$ 59,590	$ 54,699	$ 50,834

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	Year Ended December 31,		
	2010	**2009**	**2008**
Adjusted EBITDA:			
Pipeline Operations	$ 235,405	$ 229,576	$ 193,940
Terminalling & Storage	106,387	72,588	59,850
Natural Gas Storage	29,794	41,950	41,814
Energy Services	5,861	19,335	9,443
Development & Logistics	5,193	6,718	8,528
Total Adjusted EBITDA	$ 382,640	$ 370,167	$ 313,575
GAAP Reconciliation:			
Net income	$ 201,008	$ 141,637	$ 180,623
Less: net income attributable to noncontrolling interests	(157,928)	(92,043)	(154,146)
Net income attributable to Buckeye Partners, L.P.	43,080	49,594	26,477
Interest and debt expense	89,169	75,147	75,410
Income tax (benefit) expense	(919)	(343)	801
Depreciation and amortization	59,590	54,699	50,834
EBITDA	190,920	179,097	153,522
Net income attributable to noncontrolling interests affected by Merger (for periods prior to Merger) (1)	157,467	90,381	153,546
Non-cash deferred lease expense	4,235	4,500	4,598
Non-cash unit-based compensation expense	8,960	4,408	1,909
Equity plan modification expense	21,058		
Asset impairment expense		59,724	
Reorganization expense		32,057	
Adjusted EBITDA	$ 382,640	$ 370,167	$ 313,575

(1) Amounts represent portions of BGH s noncontrolling interests related to Buckeye that were eliminated as a result of the Merger. Amounts are added back for the portion of 2010 prior to the Merger, and the 2009 and 2008 periods to provide consistency with the 2010 period.

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	Year Ended December 31,		
	2010	2009	2008
Capital additions, net: (1)			
Pipeline Operations	$ 46,036	$ 34,461	$ 40,469
Terminalling & Storage	19,491	22,463	28,680
Natural Gas Storage	8,328	23,033	47,257
Energy Services	2,961	6,236	4,185
Development & Logistics	883	1,116	(119)
Total capital additions, net	$ 77,699	$ 87,309	$ 120,472
Total Assets:			
Pipeline Operations (2)	$ 1,752,920	$ 1,592,916	$ 1,630,050
Terminalling & Storage	636,095	532,971	473,806
Natural Gas Storage	549,876	573,261	503,278
Energy Services	561,382	482,025	333,967
Development & Logistics	73,943	74,476	93,309
Consolidating level (3)		230,922	228,687
Total assets	$ 3,574,216	$ 3,486,571	$ 3,263,097
Goodwill:			
Pipeline Operations	$ 198,632	$ 198,632	$ 198,632
Terminalling & Storage (4)	49,618	49,618	51,386
Natural Gas Storage	169,560	169,560	169,560
Energy Services	1,132	1,132	1,132
Development & Logistics	13,182	13,182	13,182
Total goodwill	$ 432,124	$ 432,124	$ 433,892

(1) Amounts exclude $0.4 million, ($3.3) million and $2.0 million of non-cash changes in accruals for capital expenditures for the years ended December 31, 2010, 2009 and 2008, respectively (see Note 24).

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

(3) In connection with the Merger, consolidating level assets were allocated to our business segments.

(4) 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 (in thousands):

Year Ended December 31,

	2010	2009	2008
Cash paid for interest (net of capitalized interest)	$83,852	$66,264	$63,647
Cash paid for income taxes	941	2,316	1,063
Capitalized interest	2,499	3,401	2,355
Non-cash changes in assets and liabilities:			
Change in capital expenditures in accounts payable	$ 421	$ (3,296)	$ 1,957
Environmental liability assumed in acquisition	100	1,480	5,644

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25. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data for the years ended December 31, 2010 and 2009 is set forth below (in thousands, except per LP Unit amounts). Quarterly results were influenced by seasonal and other factors inherent in our business.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2010					
Revenue	$731,174	$667,276	$734,857	$1,017,961	$3,151,268
Operating income (1)	69,491	71,939	79,513	58,558	279,501
Net income (1)	50,642	53,438	60,962	35,966	201,008
Net income attributable to Buckeye Partners, L.P. (1)	11,270	11,507	11,941	8,362	43,080
Earnings per LP unit basic (2)	$ 0.56	$ 0.58	$ 0.60	$ 0.19	$ 1.66
Earnings per LP unit diluted (2)	$ 0.56	$ 0.58	$ 0.60	$ 0.19	$ 1.65
2009					
Revenue	$416,840	$351,220	$423,444	$ 578,868	$1,770,372
Operating income (loss) (3)	68,865	(35,432)	74,889	95,478	203,800
Net income (loss) (3)	53,696	(48,384)	58,370	77,955	141,637
Net income attributable to Buckeye Partners, L.P. (3)	10,149	9,772	11,095	18,578	49,594
Earnings per LP unit basic and diluted (2)	$ 0.51	$ 0.49	$ 0.56	$ 0.93	$ 2.49

(1) The fourth quarter of 2010 includes $21.1 million of non-cash compensation expense related to the modification of an equity compensation plan (see Note 18).

(2) Historical per unit amounts have been restated for the reverse unit split. Pursuant to the Merger, BGH s unitholders received a total of approximately 20.0 million of Buckeye s LP Units in the aggregate in exchange for all outstanding BGH common units and management units. As a result, the number of Buckeye s LP Units outstanding increased from 51.6 million to 71.4 million. However, for historical reporting purposes, the impact of this change was accounted for as a reverse split of BGH s units of 0.705 to 1.0, together with the addition of Buckeye s existing LP Units. Therefore, since BGH was the surviving accounting entity, the weighted average number of LP Units outstanding used for basic and diluted earnings per LP Unit calculations are BGH s historical weighted average common units outstanding adjusted for the reverse unit split and the addition of Buckeye s existing LP Units. The sum of the per LP Unit amounts per quarter does not equal the amount presented for the year ended December 31, 2010 due to the effect of the Merger on the weighted average units outstanding calculation.

(3) 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.

26. SUBSEQUENT EVENTS

BORCO Acquisition

On December 18, 2010, we entered into a sale and purchase agreement with affiliates of First Reserve, pursuant to which we agreed to acquire First Reserve s indirect 80% interest in FRBCH, the indirect owner of BORCO. On January 18, 2011, we completed the purchase of First Reserve s 80% interest in FRBCH for approximately $1.4 billion of cash and equity. On February 16, 2011, Vopak, which owned the remaining 20% interest in FRBCH, sold its interest to us at the same proportionate price and on the same terms and conditions as those in our agreement with

First Reserve for approximately $340.0 million of cash and equity. In aggregate, we paid approximately $1.7 billion

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in a combination of cash and equity to acquire 100% of BORCO. BORCO is the fourth largest oil and petroleum products storage terminal in the world and the largest petroleum products facility in the Caribbean with current storage capacity of 21.6 million barrels.

On January 13, 2011, we sold the 4.875% Notes in an underwritten public offering. The notes were issued at 99.62% of their principal amount. Total proceeds from this offering, after underwriters fees, expenses and debt issuance costs of $4.5 million, were approximately $643.0 million, and were used to fund a portion of the purchase price for our acquisition of BORCO.

On January 18 and 19, 2011, we issued 5,794,725 LP Units and 1,314,870 Class B Units to institutional investors for aggregate consideration of approximately $425.0 million to fund a portion of the BORCO acquisition. On January 18, 2011, we issued 2,483,444 LP Units and 4,382,889 Class B Units to First Reserve as $400.0 million of consideration to fund a portion of the acquisition of an indirect interest in FRBCH. On February 16, 2011, we issued 620,861 LP Units and 1,095,722 Class B Units to Vopak as $100.0 million of consideration to fund a portion of our acquisition of Vopak s 20% interest in BORCO. The remaining purchase price was funded with cash on hand at closing and borrowings under our Credit Facility.

The results of operations of the BORCO acquisition will be included in our consolidated financial statements at the date of acquisition and will be included in our Terminalling & Storage segment. The acquisition cost will be allocated to assets acquired and liabilities assumed based on estimated preliminary fair values at the acquisition date, with amounts exceeding the fair value to be recorded as goodwill. We are in the process of preparing a fair value analysis of the assets acquired and liabilities assumed. We expect to finalize the purchase price allocation during 2011.

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.

There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) or in other factors during the fourth quarter of 2010, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. ***Other Information***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information required by this item will be included in our definitive Proxy Statement in connection with our 2011 Annual Meeting of Unitholders (the 2011 Proxy Statement), which will be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2010, under the headings Proposal One: Election of Directors, Executive Officers and Section 16(a) Beneficial Ownership Reporting Compliance and is incorporated herein by reference.

Item 11. ***Executive Compensation***

The information required by this item will be set forth in our 2011 Proxy Statement under the headings Compensation of Directors, Compensation Discussion and Analysis, Executive Compensation and Compensation Committee Interlocks and Insider Participation and is incorporated herein by reference.

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Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters***

The information required by this item will be set forth in our 2011 Proxy Statement under the headings Security Ownership of Management and Certain Beneficial Owners and Equity Compensation Plans and is incorporated herein by reference.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information required by this item will be set forth in our 2011 Proxy Statement under the headings Independence of Directors and Related Person Transactions and Procedures and is incorporated herein by reference.

Item 14. ***Principal Accounting Fees and Services***

The information required by this item will be included in our 2011 Proxy Statement under the heading Fees Paid to Deloitte & Touche LLP and is incorporated herein by reference.

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).
2.5	First Amended and Restated Agreement and Plan of Merger, dated August 18, 2010, by and among Buckeye Partners, L.P., Buckeye GP LLC, Buckeye GP Holdings L.P., MainLine Management LLC and Grand Ohio, LLC (Incorporated by reference to Annex A to Buckeye Partners, L.P. s Registration Statement on Form S-4/A filed on August 19, 2010).

2.6 First Amendment to First Amended and Restated Agreement and Plan of Merger, dated October 29, 2010, by and among Buckeye Partners, L.P., Buckeye GP LLC, Buckeye GP Holdings L.P., MainLine Management LLC and Grand Ohio, LLC (Incorporated by reference to Exhibit 2.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on November 3, 2010).

2.7 Sale and Purchase Agreement by and among FR XI Offshore AIV, L.P., FR Borco GP Ltd., and Buckeye Atlantic Holdings LLC of FR Borco L.P. dated as of December 18, 2010 (Incorporated by reference to Exhibit 2.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on December 21, 2010).

2.8 Sale and Purchase Agreement by and among Vopak Bahamas B.V., Koninklijke Vopak N.V. and Buckeye Atlantic Holdings LLC dated as of February 15, 2011 (Incorporated by reference to Exhibit 2.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on February 22, 2011).

3.1 Amended and Restated Certificate of Limited Partnership of Buckeye Partners, L.P., dated as of February 4, 1998 (Incorporated by reference to Exhibit 3.2 of Buckeye Partners, L.P. s Annual Report on Form 10-K for the year ended December 31, 1997).

3.2 Certificate of Amendment to Amended and Restated Certificate of Limited Partnership of Buckeye Partners, L.P., dated as of April 26, 2002 (Incorporated by reference to Exhibit 3.2 of Buckeye Partners, L.P. s Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2002).

3.3 Certificate of Amendment to Amended and Restated Certificate of Limited Partnership of Buckeye Partners, L.P., dated as of June 1, 2004, effective as of June 3, 2004 (Incorporated by reference to Exhibit 3.3 of the Buckeye Partners, L.P. s Registration Statement on Form S-3 filed June 16, 2004).

3.4 Certificate of Amendment to Amended and Restated Certificate of Limited Partnership of Buckeye Partners, L.P., dated as of December 15, 2004 (Incorporated by reference to Exhibit 3.5 of Buckeye Partners, L.P. s Annual Report on Form 10-K for the year ended December 31, 2004).

3.5 Amended and Restated Agreement of Limited Partnership of Buckeye Partners, L.P., dated as of November 19, 2010 (Incorporated by reference to Exhibit 3.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed November 22, 2010).

3.6 Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Buckeye Partners, L.P., dated as of January 18, 2011 (Incorporated by reference to Exhibit 3.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on January 20, 2011).

4.1 Indenture dated as of July 10, 2003, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Registration Statement on Form S-4 filed September 19, 2003).

4.2 First Supplemental Indenture dated as of July 10, 2003, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.2 of Buckeye Partners, L.P. s Registration Statement on Form S-4 filed September 19, 2003).

4.3 Second Supplemental Indenture dated as of August 19, 2003, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.3 of Buckeye Partners, L.P. s Registration Statement on Form S-4 filed September 19, 2003).

4.4 Third Supplemental Indenture dated as of October 12, 2004, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on October 14, 2004).

4.5 Fourth Supplemental Indenture dated as of June 30, 2005, between Buckeye Partners, L.P. and SunTrust Bank, as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on June 30, 2005).

4.6 Fifth Supplemental Indenture dated as of January 11, 2008, between Buckeye Partners, L.P. and U.S. Bank National Association (successor to SunTrust Bank), as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on January 11, 2008).

4.7	Sixth Supplemental Indenture dated as of August 18, 2009, between Buckeye Partners, L.P. and U.S. Bank National Association (successor-in-interest to SunTrust Bank), as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on August 24, 2009).
4.8	Seventh Supplemental Indenture dated as of January 13, 2011, between Buckeye Partners, L.P. and U.S. Bank National Association (successor-in-interest to SunTrust Bank), as Trustee (Incorporated by reference to Exhibit 4.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on January 20, 2011).
4.9	Registration Rights Agreement, by and among Buckeye Partners, L.P., BGH GP Holdings, LLC, ArcLight Energy Partners Fund III, L.P., ArcLight Energy Partners Fund IV, L.P., Kelso Investment Associates VIII, L.P. and KEP VI, LLC (Incorporated by reference to Exhibit 10.2 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on June 11, 2010).
4.10	Registration Rights Agreement by and among Buckeye Partners, L.P., FR XI Offshore AIV, L.P. and the other investors named therein, dated as of December 18, 2010 (Incorporated by reference to Exhibit 10.4 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on December 21, 2010).
4.11	Registration Rights Agreement by and among Buckeye Partners, L.P. and the investors named therein, dated as of December 18, 2010 (Incorporated by reference to Exhibit 10.5 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on December 21, 2010).
4.12	Registration Rights Agreement by and between Buckeye Partners, L.P. and Vopak Bahamas B.V. dated as of February 15, 2011 (Incorporated by reference to Exhibit 10.2 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on February 22, 2011).
10.1	Second Amended and Restated Agreement of Limited Partnership of Buckeye GP Holdings L.P., dated as of November 19, 2010 (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on November 22, 2010).
10.2	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).
10.3	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).
10.4	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).
*10.5	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).
*10.6	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).
*10.7	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).
*10.8	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).

*10.9	Buckeye Partners, L.P. Annual Incentive Compensation Plan, as amended and restated, effective as of January 1, 2010 (Incorporated by reference to Exhibit 10.13 of Buckeye Partners, L.P. s Annual Report on Form 10-K for the year ended December 31, 2009).
*10.10	Buckeye Partners, L.P. Annual Incentive Compensation Plan, as Amended and Restated, effective as of May 6, 2010 (Incorporated by reference to Exhibit 10.15 of Buckeye Partners, L.P. s Registration Statement on Form S-4 filed on July 14, 2010).
*10.11	Buckeye Partners, L.P. Annual Incentive Compensation Plan, as Amended and Restated, effective as of January 1, 2011 (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on January 19, 2011).
*10.12	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).
10.13	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).
10.14	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).
10.15	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).
10.16	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).
10.17	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).
**10.18	Fifth Amendment to Credit Agreement, dated May 28, 2010 among Buckeye Partners, L.P., SunTrust Bank, as administrative agent, and the lenders signatory thereto.
10.19	Sixth Amendment to Credit Agreement, dated September 29, 2010, 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 Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2010).
**10.20	Seventh Amendment to Credit Agreement, dated December 13, 2010, among Buckeye Partners, L.P., SunTrust Bank, as administrative agent, and the lenders signatory thereto.

10.21	Eighth Amendment of Credit Agreement, dated December 18, 2010, among Buckeye Partners, L.P., its subsidiaries, SunTrust Bank, as administrative agent, and the lenders signatory thereto (Incorporated by reference to Exhibit 10.6 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on December 21, 2010).
10.22	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).
10.23	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).

10.24	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).
10.25	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).
10.26	Amended and Restated Credit Agreement, dated as of June 25, 2010, among Buckeye Energy Services LLC, BNP Paribas and other lenders party thereto (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on July 1, 2010).
10.27	Support Agreement, by and among Buckeye Partners, L.P., BGH GP Holdings, LLC, ArcLight Energy Partners Fund III, L.P., ArcLight Energy Partners Fund IV, L.P., Kelso Investment Associates VIII, L.P. and KEP VI, LLC (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on June 11, 2010).
10.28	Unit Purchase Agreement by and between Buckeye Partners, L.P. and FR XI Offshore AIV, L.P. dated as of December 18, 2010 (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on December 21, 2010).
10.29	LP Unit Purchase Agreement by and among Buckeye Partners, L.P. and purchasers named therein dated as of December 18, 2010 (Incorporated by reference to Exhibit 10.2 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on December 21, 2010).
10.30	Class B Unit Purchase Agreement by and among Buckeye Partners, L.P. and purchasers named therein dated as of December 18, 2010 (Incorporated by reference to Exhibit 10.3 of Buckeye Partners, L.P. s Current Report on Form 8-K filed on December 21, 2010).
10.31	Unit Purchase Agreement by and between Buckeye Partners, L.P. and Vopak Bahamas B.V. dated as of February 15, 2011 (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report of Form 8-K filed on February 22, 2011).
10.32	Transition Support Agreement by and among Buckeye Atlantic Holdings LLC, Vopak Bahamas B.V., FR Borco Topco L.P., FR Borco Coop Holdings, L.P., FR Borco Coop Holdings GP Limited, Bahamas Oil Refining Company International Limited and Vopak Koninklijke N.V. dated as of February 15, 2011 (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P. s Current Report of Form 8-K filed on February 22, 2011).
**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.
**101.INS	XBRL Instance Document.
**101.SCH	XBRL Taxonomy Extension Schema Document.
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

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* Represents management contract or compensatory plan or arrangement.

** Filed herewith.

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

(a) 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 28, 2011	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 28, 2011	By: /s/ C. Scott Hobbs C. Scott Hobbs *Director*
Dated: February 28, 2011	By: /s/ Joseph A. LaSala, Jr. Joseph A. LaSala, Jr. *Director*
Dated: February 28, 2011	By: /s/ Mark C. McKinley Mark C. McKinley *Director*
Dated: February 28, 2011	By: /s/ Oliver G. Rick Richard, III Oliver Rick G. Richard, III *Director*
Dated: February 28, 2011	By: /s/ Frank S. Sowinski Frank S. Sowinski *Director*
Dated: February 28, 2011	By: /s/ Keith E. St.Clair Keith E. St.Clair *Senior Vice President and Chief Financial Officer* *(Principal Financial Officer)*

Dated: February 28, 2011	By: /s/ Martin A. White Martin A. White *Director*
Dated: February 28, 2011	By: /s/ Forrest E. Wylie Forrest E. Wylie *Director*
Dated: February 28, 2011	By: /s/ Jeffrey I. Beason Jeffrey I. Beason *Vice President and Controller* *(Principal Accounting Officer)*

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