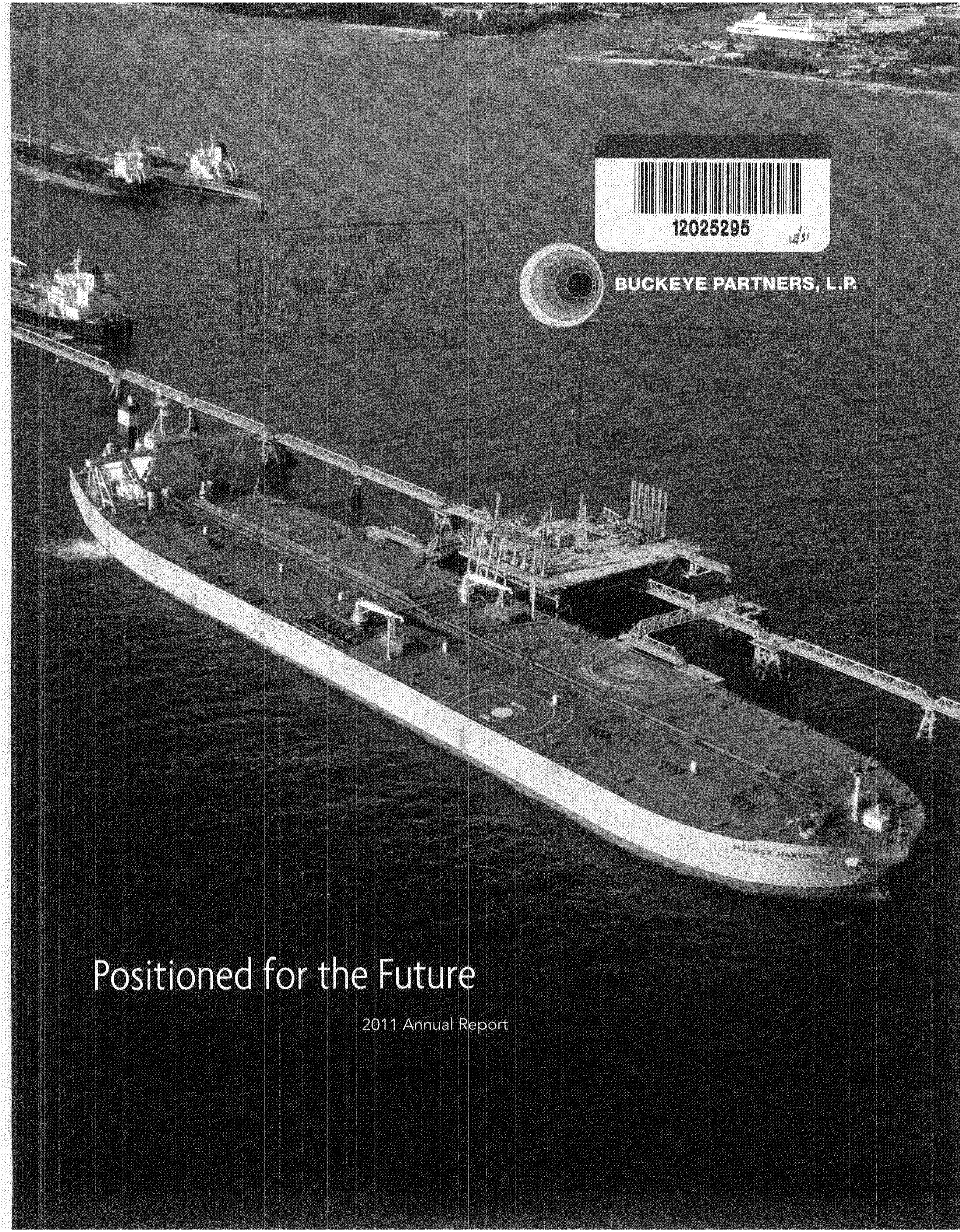
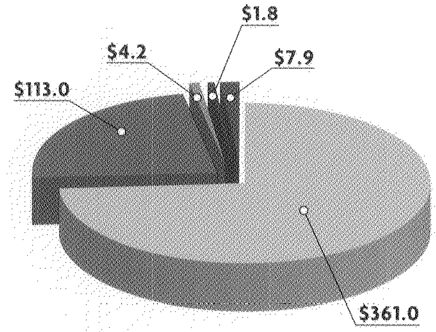


BUCKEYE PARTNERS, L.P.

Positioned for the Future

2011 Annual Report

2011 Adjusted EBITDA[1] Contribution by Segment *(in millions)*



In 2011, Buckeye celebrated its 125th year as a midstream energy company and its 25th year as an MLP listed on the New York Stock Exchange.

PIPELINES & TERMINALS
Buckeye owns and operates approximately 6,100 miles of pipeline located primarily in the Northeast and Midwest United States. We transport approximately 1.3 million barrels of liquid petroleum products per day to more than 100 delivery points. This segment also includes approximately 100 active terminals with aggregate storage capacity of over 37 million barrels.

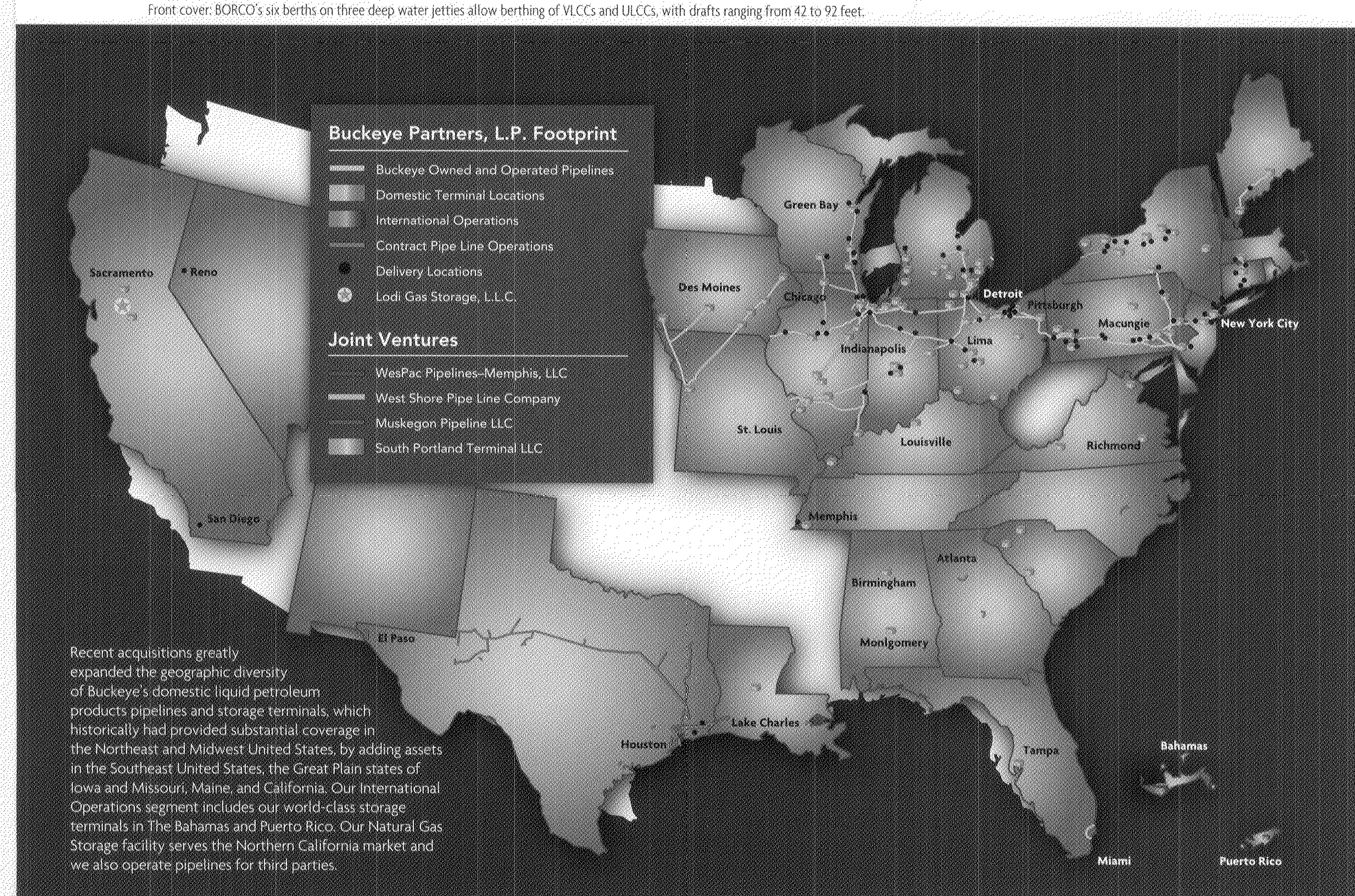
INTERNATIONAL OPERATIONS
Buckeye owns over 26 million barrels of storage capacity at two terminal facilities, located in The Bahamas (~ 21 million barrels) and Puerto Rico (~ 5 million barrels), with deep water berthing capability to handle ULCCs and VLCCs in The Bahamas.

NATURAL GAS STORAGE
Buckeye's Lodi Gas Storage facility is a high-performance natural gas storage facility with approximately 30 Bcf of working gas capacity in Northern California serving the greater San Francisco Bay market.

ENERGY SERVICES
Buckeye Energy Services (BES) markets refined petroleum products and other ancillary products in areas served by Buckeye's pipelines and terminals, with over 1.3 billion gallons of products sold in 2011.

DEVELOPMENT & LOGISTICS
Buckeye Development & Logistics (BDL) operates and maintains approximately 2,800 miles of third-party pipelines under agreements with major oil and gas, petrochemical, and chemical companies.

[1]See definition of Non-GAAP measures and reconciliations to GAAP measures at the end of this report.
Front cover: BORCO's six berths on three deep water jetties allow berthing of VLCCs and ULCCs, with drafts ranging from 42 to 92 feet.



Recent acquisitions greatly expanded the geographic diversity of Buckeye's domestic liquid petroleum products pipelines and storage terminals, which historically had provided substantial coverage in the Northeast and Midwest United States, by adding assets in the Southeast United States, the Great Plain states of Iowa and Missouri, Maine, and California. Our International Operations segment includes our world-class storage terminals in The Bahamas and Puerto Rico. Our Natural Gas Storage facility serves the Northern California market and we also operate pipelines for third parties.

About Us

Buckeye Partners, L.P. (NYSE: BPL) is a publicly traded master limited partnership that owns and operates one of the largest independent liquid petroleum products pipeline systems in the United States in terms of volumes delivered, with over 6,000 miles of pipeline. Buckeye also owns more than 100 liquid petroleum products terminals with aggregate storage capacity of approximately 64 million barrels, operates approximately 2,800 miles of pipeline under agreements with major oil and chemical companies, owns a high-performance natural gas storage facility in Northern California, and markets liquid petroleum products in certain regions served by its pipeline and terminal operations. Buckeye's flagship marine terminal in The Bahamas, BORCO, is one of the largest crude oil and petroleum products storage facilities in the world, serving the international markets as a premier global logistics hub. In 2011, Buckeye celebrated its 125th anniversary as a midstream energy company. More information concerning Buckeye can be found at www.buckeye.com.

Financial and Operating Highlights

Selected Financial Data	**2011**	2010	2009	2008	2007
(Dollars in millions, except unit, per unit, and operating data)					
Revenue	**$4,759.6**	$3,151.3	$1,770.4	$1,896.7	$519.3
Operating Income Before Special Charges[1][2]	**358.4**	300.6	295.6	246.5	195.4
Net Income Attributable to Buckeye Partners, L.P.	**108.5**	43.1	49.6	26.5	22.9
Adjusted EBITDA[2]	**487.9**	382.6	370.2	313.6	248.5
Cash Distributions Per Limited Partner Unit	**4.03**	3.83	3.63	3.43	3.23
Weighted Average Number of LP Units Outstanding—Diluted (in thousands)	**90,772**	26,086	19,952	19,952	19,952
Operating Data					
Pipeline Volumes (Thousands of barrels per day)	**1,347.5**	1,304.5	1,309.9	1,382.2	1,447.4
Average Tariff Rate (Cents per barrel)	**76.8**	73.6	72.1	67.6	64.7
Domestic Terminal Throughput (Thousands of barrels per day)	**742.8**	562.5	471.9	464.4	482.3
Refined Product Sales (Millions of gallons)	**1,337.8**	1,139.1	655.1	435.2	—

[1] Operating income before special charges excludes the 2011 goodwill impairment expense, the 2010 equity plan modification expense, and the 2009 asset impairment and reorganization expense.

[2] See definition of Non-GAAP measures and reconciliations to GAAP measures at the end of this report.

Dear Valued Unitholders:

On February 10, 2012, Clark C. Smith became Buckeye's Chief Executive Officer, succeeding Forrest E. Wylie who continues to serve Buckeye as Non-Executive Chairman of the Board.

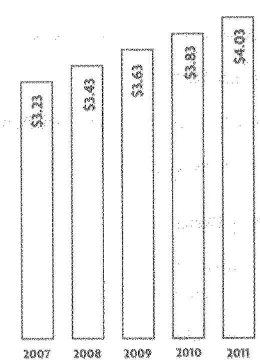
2011 was a year of milestones for Buckeye. We celebrated 125 years of continuous operations as a midstream energy company. What started as a Standard Oil crude oil pipeline from the western Pennsylvania oilfields to Cleveland, Ohio refineries in 1886 has grown into over 6,000 miles of pipeline and 64 million barrels of crude oil and liquid petroleum product storage spanning 22 states, Puerto Rico, and The Bahamas today. We also celebrated our 25th year as a publicly traded master limited partnership listed on the New York Stock Exchange. We successfully integrated the Bahamas Oil Refining Company International, or BORCO, facility, the largest acquisition in our long history, which expanded our footprint into the international logistics market. We initiated and have already begun delivering on the most ambitious growth capital expansion project in our history at the BORCO facility to further enhance the capabilities of our international assets. We also expanded our domestic geographic footprint with the completion of the acquisition and successful integration of a significant portfolio of terminals and pipelines from BP North America, which represented the latest successful iteration of our terminal acquisition franchise.

Many of the above achievements contributed to our record results for 2011. In addition, 2011 benefited from our continued commitment to best-in-class customer service, operational excellence, an unwavering commitment to safety, and optimization of our assets, combined with an entrepreneurial approach toward asset acquisition and development. We continue to reap benefits from the empowerment of our talented, valued employees, as evidenced by the continued improvement in Buckeye's productivity and profitability.

Commitment to Safety

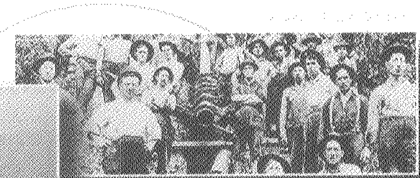
I am pleased to report that Buckeye was able to achieve substantial growth in 2011 while maintaining safe, reliable, and environmentally responsible operations. Buckeye's commitment to best-in-class operations is demonstrated by the fact that zero lost-time injuries were incurred across Buckeye's operations in 2011. Further, the project team at our new BORCO facility celebrated a milestone of over 750,000

Distributions Paid



1886-2011 Celebrating 125 Years of Service

1886 The Buckeye Pipe Line Company was organized (part of the Standard Oil Trust) to transport oil from fields near Lima, Ohio to Standard's refineries.



1888 Buckeye constructs 8-inch pipelines from Lima to Chicago and Cygnet to Mantua.

man-hours of work without a lost-time incident while managing significant construction activities related to our expansion plans. Safety remains the highest priority at Buckeye and these excellent statistics demonstrate how our employees remain focused even as we integrate significant acquisitions and undertake substantial capital projects.

Financial Summary

Buckeye achieved record adjusted EBITDA for 2011 of $487.9 million compared to $382.6 million for 2010.[1] Our Adjusted EBITDA, excluding transition expenses related to acquisition and integration activities, was $505.0 million, an increase of 31 percent over 2010 similarly adjusted. This increase was primarily the result of the acquisition of our BORCO facility and its contribution to our 2011 results.

We also continued our uninterrupted history of quarterly cash distribution increases with the announcement of our 31st consecutive distribution increase for the quarter ended December 31, 2011. Distributions paid in 2011 totaled $4.025 per unit, representing a $0.20 per unit, or 5.2 percent, increase over 2010 cash distributions. We are proud of our history of payment of cash distributions in each quarter since becoming a publicly traded partnership in 1986.

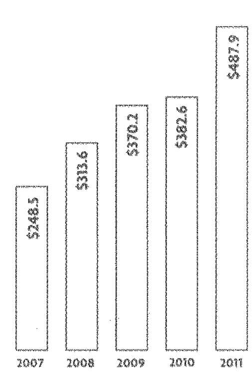
As one of the first publicly traded master limited partnerships, Buckeye has the longest track record of consecutive quarterly distributions among our MLP peers.

Positioning for the Future

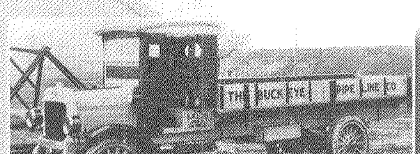
Surviving and prospering for 125 years has required Buckeye to demonstrate the ability to anticipate global trends impacting our business and position our Partnership to capitalize on these trends. We believe a significant shift in refined product supply to the Northeast United States is underway as a result of the decline in east coast refining capacity, evidenced by the 2011 announcements regarding the anticipated shut down of over 50 percent of the refining capacity in the region.[2] We believe that a significant portion of the idled refinery supply will be replaced by refined products imported from refining centers in Europe as well as the Middle and Far East. The global refined products logistics market will experience significant growth and increase in importance in supplying many of the markets we serve. We have developed and are executing a strategy to position Buckeye to participate in these global logistics markets.

Our 2011 acquisition of the BORCO facility in The Bahamas was an important first step in positioning Buckeye for the future. BORCO is a world-class marine storage facility located only 80 miles from the coast of Florida, and 920 miles from New York Harbor where one of our major pipeline systems originates. BORCO has 21.4 million barrels of storage capacity and has additional unused land available to double the existing storage capacity. It benefits from deep water access capable of berthing the largest petroleum carriers currently in service. BORCO has significantly expanded our geographic footprint into new markets as well as further diversified the products we handle. Most importantly, BORCO serves as Buckeye's introduction into the global petroleum logistics markets, as its advantaged location and service capabilities act as a key gateway for global petroleum products flows between North and South America as well as the Middle and Far East.

Adjusted EBITDA[1]
(In millions)



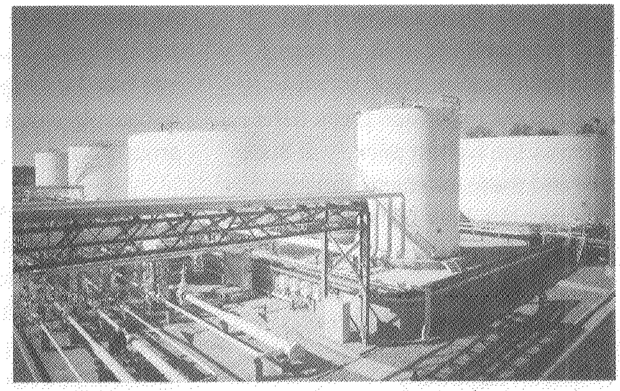
[1] See definition of Non-GAAP measures and reconciliations to GAAP measures at the end of this report.
[2] According to February 2012 EIA Report titled, "Potential Impacts of Reductions in Refinery Activity on Northeast Petroleum Product Markets."



1945
Buckeye moves from solely crude oil transportation to both crude and refined products transportation.

1967 New York Transit Company and Northern Pipe Line Company are merged into The Buckeye Pipe Line Company.

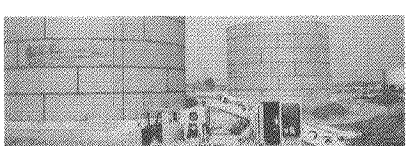
The Perth Amboy facility, along with our BORCO facility, is a key component of a long-term strategy to create a more fully integrated and flexible system that offers our customers unparalleled connectivity and service capabilities.


The Pipelines & Terminals segment transports refined petroleum products from major supply sources to terminals and airports located within end-use markets and provides storage and throughput services.

Our integration of this facility, as with all facilities we acquire, included implementing our best practices operating model to improve productivity and utilization at the lowest cost without compromising our commitment to safety and environmentally responsible operations. Our employees identified a number of potential productivity improvements, some of which have been implemented and others which we continue to analyze. We also initiated the largest internal growth capital investment plan in our long history that will result in 7.9 million barrels of storage capacity being added to this facility, with this additional capacity scheduled to be placed in-service over the next three to four years beginning in 2012. Buckeye is already benefiting from the completion of two significant projects in 2011: the refurbishment of one of our offshore jetties, which increases our capacity to berth the largest petroleum carriers in the world, and the construction of an inland dock providing inclement weather berthing capabilities.

Connecting the Dots

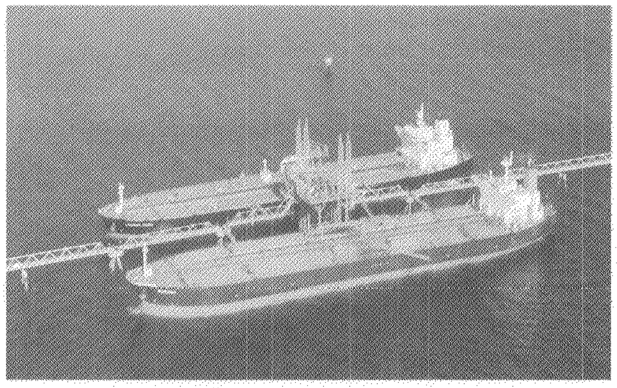
We are very excited about our recent announcement of an agreement to acquire from Chevron a four million barrel terminal storage facility in the New York Harbor. This acquisition reflects Buckeye's efforts to enhance the competitive supply alternatives for our pipelines and terminals in the Northeast by ensuring direct access to waterborne imports of refined petroleum products. The facility, located in Perth Amboy, New Jersey, boasts three active docks including one ship dock with up to 37 feet of draft. Access to New York Harbor will allow the facility to serve as a key import terminal connecting Buckeye's extensive inland pipeline system with imported products, which could include products imported through our BORCO marine terminal. Our integration plans include a direct pipeline link to our Linden complex, which is a key origination point for our Northeast pipeline system, as well as other significant growth capital projects at the facility that are anticipated to yield substantial incremental contributions to our financial results. The Perth Amboy facility, along with our BORCO facility, is a key component of a long-term strategy to create a more fully integrated and flexible system that offers our customers unparalleled connectivity and service capabilities. Execution on this strategy will continue to differentiate our service offerings and provide sustainability and optionality for future growth in our core business.


1974 The 20-inch products pipeline is constructed from Linden, New Jersey to Macungie, Pennsylvania.

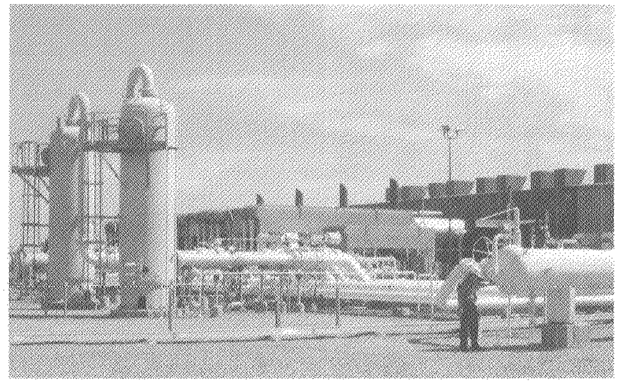
1982 The Allentown, Pennsylvania administrative office opens to accomodate combining staff from a satellite office with Macungie office.


Photo: Selkirk Miller

1986 Buckeye became the first pipeline company to become a master limited partnership selling 12 million units in an initial public offering listed on the NYSE under "BPL" at $20/unit on Dec. 23, 1986.



The International Operations segment provides bulk storage, berthing, heating, blending, and other ancillary services at two marine terminals in The Bahamas and Puerto Rico.



The Natural Gas Storage segment services natural gas demand in the San Francisco and Sacramento, California areas through its connection to Pacific Gas and Electric's intrastate gas pipeline system.

Terminal Growth Franchise

A significant cornerstone of our growth strategy in recent years has been the acquisition of assets sold by the major integrated petroleum companies. We refer to our ability to quickly integrate these spun-off assets while unlocking significant value through the application of our best practice formula as our terminal franchise. The 2011 acquisition of 33 terminals and over 600 miles of pipeline from BP North America was the latest opportunity for us to execute our terminal franchise. The acquisition facilitated our participation in several growth markets previously outside of our system footprint and allowed us to realize operating synergies with some of our existing assets. We have successfully implemented several commercial development initiatives to increase the value of these assets to our unitholders.

Operations Review

The following is a summary of our operating highlights for 2011[3]:

PIPELINES & TERMINALS

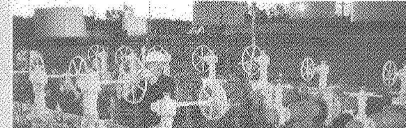
- Adjusted EBITDA from our Pipelines & Terminals segment was $361.0 million in 2011 compared to $346.4 million the previous year. Pipeline volumes increased by approximately three percent primarily as a result of volumes moved on acquired pipelines. Strength in distillate volumes on our legacy pipelines were offset by some weakness in gasoline and heating oil movements. Terminalling volumes increased by 32 percent, benefiting from the BP terminals acquired in June 2011. Results for the year also benefited from higher pipeline tariff rates and terminalling contract rate escalations.
- We are executing a number of internal growth projects expected to be completed during 2012, including expanded pipeline capacity from New York Harbor into Pennsylvania and Upstate New York markets.

INTERNATIONAL OPERATIONS

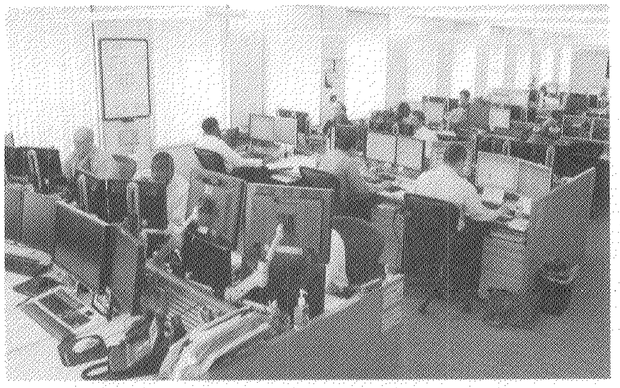
- Our International Operations segment, which includes results of our BORCO and Yabucoa marine terminals, produced $113.0 million of Adjusted EBITDA in 2011. We acquired 80 percent of BORCO on January 18, 2011 and the remaining 20 percent on February 16, 2011. Approximately 83 percent of 2011 revenue at our BORCO facility was derived from take-or-pay storage contracts with the remainder consisting of variable berthing and other ancillary revenues.

[3] See definition of Non-GAAP measures and reconciliations to GAAP measures at the end of this report.

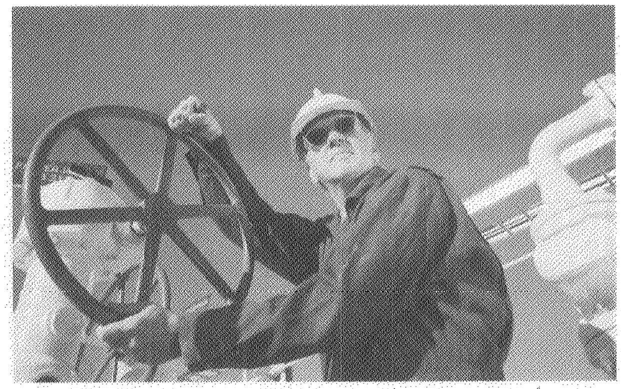
1999 Buckeye created Buckeye Gulf Coast Pipe Lines, L.P. when it acquired certain assets from a Texas-based energy company.



2004 Buckeye completes one of the largest acquisitions in its history with the addition of 5 products pipelines totaling approximately 900 miles and 24 products terminals with approximately 9.3 million barrels of storage.



The Energy Services segment is a wholesale distributor of refined petroleum products in the U.S. in areas also served by our pipelines and terminals, allowing Buckeye to increase utilization of its pipeline and terminal assets.



The Development & Logistics segment provides operation and maintenance services for major oil and gas, petrochemical, and chemical companies under third-party contracts and owns and operates two underground propane storage caverns in Indiana and Illinois.

- We initiated construction on the first phase of a $350 to $400 million expansion project expected to provide up to an additional 7.9 million barrels of storage capacity with approximately 1.9 million barrels expected to be in-service in 2012.

NATURAL GAS STORAGE

- Adjusted EBITDA from our Natural Gas Storage segment was $4.2 million for 2011 compared to $29.8 million in 2010. Results of this segment were negatively impacted by low natural gas prices, compressed seasonal spreads, and lack of price volatility.

ENERGY SERVICES

- Our Energy Services segment produced $1.8 million of Adjusted EBITDA for the year compared to $5.9 million in the prior year. 2011 results were impacted by severe basis weakness in the fourth quarter driven by changing supply fundamentals in the Northeast and Midwest markets.

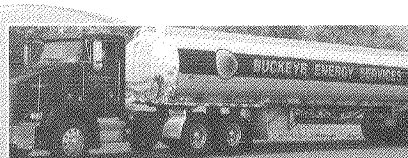
DEVELOPMENT & LOGISTICS

- Our Development & Logistics segment earned $7.9 million of Adjusted EBITDA for 2011, compared to $5.2 million in 2010, from the contract operation of 2,800 miles of pipelines and 1.4 million barrels of storage capacity.

Our top priorities for 2012 include the successful completion and integration of our Perth Amboy acquisition, which we expect to close late in the second quarter of the year. In addition, we are focused on the safe and successful execution of our strategic growth capital projects at our BORCO facility and those planned for the Perth Amboy facility after the acquisition closes. We will continue to pursue growth opportunities that deliver value to our unitholders and complement our existing asset portfolio.

We look forward to being able to report on the achievement of important milestones in our growth strategy during 2012, Buckeye's 126th year of operations.

Clark C. Smith
President and Chief Executive Officer



2008 Buckeye acquires Farm & Home Oil Company, a significant distributor of gasoline and distillate products in the Northeastern U.S., which merged with Buckeye Energy Services.

2011 Buckeye completes acquisition of 100% interest in Bahamas Oil Refining Company International.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2011

OR

☐ **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from to

Commission file number 1-9356

Buckeye Partners, L.P.
(Exact name of registrant as specified in its charter)

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

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

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 ☒ 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 ☒

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 ☒ 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 ☒ 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 ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

At June 30, 2011, the aggregate market value of the registrant's limited partner units and Class B units held by non-affiliates was $5.9 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 21, 2012: 90,279,384 and 7,304,880, respectively.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement being prepared for the solicitation of proxies in connection with the 2012 Annual Meeting of Limited Partners are incorporated by reference in Part III of this Form 10-K.

TABLE OF CONTENTS

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information contained in this Annual Report on Form 10-K (this "Report") includes "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 developments, (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, (8) changes in supply and demand in the markets in which we sell refined petroleum products, (9) volatility in the value of natural gas storage services, which is driven by unfavorable natural gas prices, including low seasonal price differentials and low price volatility, (10) nonpayment or nonperformance by our customers, (11) our ability to integrate acquired assets with our existing assets and to realize anticipated cost savings and other efficiencies, (12) our ability to successfully complete our organic growth projects and to realize anticipated financial benefits, and (13) our ability to complete our previously announced acquisition of a terminal in Perth Amboy, New Jersey. 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" and in "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, caution should be taken not to place undue reliance on any such forward-looking statements because such statements speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason. 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.

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 ("Buckeye"). 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*" are intended to mean the business and operations of Buckeye Partners, L.P. and its consolidated subsidiaries.

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 6,100 miles of pipeline and over 100 active products terminals that provide aggregate storage capacity of approximately 64 million barrels. We also operate and maintain approximately 2,800 miles of third-party 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 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. Our flagship marine terminal in The Bahamas, Bahamas Oil Refining Company International Limited ("BORCO") is one of the largest marine crude oil and petroleum products storage facilities in the world, serving the international markets as a premier global logistics hub.

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.

Business Strategy

Our primary business objective is to provide stable and sustainable cash distributions to our LP 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 through accretive acquisitions and organic growth projects; 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.

Recent Developments

2012 Transactions

On February 9, 2012, we signed a definitive agreement with Chevron U.S.A. Inc. ("Chevron") to acquire a marine terminal facility for liquid petroleum products in New York Harbor (the "Perth Amboy Facility") for $260.0 million in cash. The facility, which sits on approximately 250 acres on the Arthur Kill in Perth Amboy, New Jersey, has over 4 million barrels of tankage, four docks, and significant undeveloped land available for potential expansion. The Perth Amboy Facility has water, pipeline, rail, and truck access, and is located only six miles from our Linden, New Jersey complex. Chevron entered into multi-year storage, blending, and throughput commitments with us concurrent with the acquisition. The Perth Amboy Facility will provide a link between our inland pipelines and terminals and our BORCO facility in The Bahamas, improving service offerings for our customers and providing further support to our planned clean products tankage expansion at the BORCO facility. The operations of the Perth Amboy Facility will be reported in our Pipelines & Terminals segment following closing, which is expected to close in the latter half of the second quarter of 2012.

On February 13, 2012, we issued 4,262,575 LP units to institutional investors in a registered direct offering for aggregate consideration of approximately $250.0 million at a price of $58.65 per LP Unit, before deducting placement agents fees and estimated offering expenses. We plan to use the net proceeds from this offering to fund indirectly a portion of the Perth Amboy Facility and certain other growth capital expenditures, and, pending such uses, to reduce the indebtedness outstanding under our Credit Facility (as defined in "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources").

For additional information, see Note 28 in the Notes to the Consolidated Financial Statements.

2011 Transactions

Acquisitions

On July 19, 2011, we acquired, from an affiliate of ExxonMobil Corporation ("ExxonMobil") for $23.5 million in cash, a terminal in Bangor, Maine ("Bangor Terminal") with approximately 140,000 barrels of storage capacity, a terminal in Portland, Maine ("South Portland Terminal") with approximately 725,000 barrels of storage capacity through a 50/50 joint venture with Irving Oil Terminals Inc. ("Irving") and a 124-mile pipeline that connects the two terminals. We believe this acquisition reflects our efforts to diversify into new geographic regions and to increase our marine terminals presence. The South Portland terminal is operated by our Development & Logistics segment. The pipeline, Bangor Terminal and equity investment are reported in the Pipelines & Terminals segment. We financed this acquisition with borrowings under our Prior BPL Credit Facility (as defined in "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources").

On June 1, 2011, we acquired 33 refined petroleum products terminals with total storage capacity of over 10 million barrels and approximately 650 miles of refined petroleum products pipelines from BP Products North America Inc. and its affiliates ("BP") for $166.0 million. The terminal and pipeline assets are located in 13 states situated in the Midwestern, Southeastern and Western United States. BP entered into multiple commercial contracts with us concurrent with the acquisition relating to the continued usage of these assets. We believe the acquisition of these assets further extends our operations into new, key geographic markets. The operations of these acquired assets are reported in the Pipelines & Terminals segment. We funded this acquisition with borrowings under our Prior BPL Credit Facility.

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

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

On January 13, 2011, we issued $650.0 million aggregate principal amount of 4.875% Notes due 2021 (the "4.875% Notes") in an underwritten public offering to fund a portion of the purchase price of the BORCO acquisition. The notes were issued at 99.62% of their principal amount.

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, and 2,483,444 LP Units and 4,382,889 Class B Units to First Reserve as $400.0 million of consideration. 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. These issuances were used to fund a portion of the BORCO acquisition. The remaining purchase price was funded with cash on hand at closing and borrowings under our Prior BPL Credit Facility.

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

See Note 3 in the Notes to Consolidated Financial Statements for further information on our acquisitions.

Dispositions

On May 11, 2011, we sold our 20% interest in West Texas LPG Pipeline Limited Partnership ("WT LPG") to affiliates of Atlas Pipeline Partners L.P. for $85.0 million. WT LPG owns a 2,295-mile common-carrier pipeline system that transports natural gas liquids from points in New Mexico and Texas to Mont Belvieu, Texas for fractionation. Chevron Pipeline Company, which owns the remaining 80% interest, is the operator of WT LPG. The proceeds from the sale were used to fund a portion of our internal growth capital projects planned for 2011. We recognized a gain of $34.7 million on the sale of our interest in WT LPG.

Equity Offerings

On April 15, 2011, we issued 5,520,000 LP Units, which included 720,000 LP Units issued as part of the overallotment option, in an underwritten public offering at a public offering price of $59.41 per LP Unit. Total proceeds from the offering, including the overallotment option and after the underwriters' discount of $1.99 per LP Unit and offering expenses, were approximately $316.6 million, and were used to reduce amounts outstanding under our Prior BPL Credit Facility.

Business Activities

The following discussion describes the business activities of our business segments, which include Pipelines & Terminals, International Operations, Natural Gas Storage, Energy Services and Development & Logistics. The Pipelines & Terminals segment and the Energy Services segment 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 operations and assets are conducted and located in the continental United States, except for our terminals located in Puerto Rico and The Bahamas. Detailed financial information regarding revenue, operating income (loss) and total assets of each segment can be found in Note 25 in the Notes to Consolidated Financial Statements. The following table shows our consolidated revenue and each segment's revenue and percentage of consolidated revenue for the periods indicated (revenue in thousands):

	Year Ended December 31,					
	2011		2010		2009	
	Revenue	Percent	Revenue	Percent	Revenue	Percent
Pipelines & Terminals	$ 631,289	13.2%	$ 574,990	18.3%	$ 529,243	30.0%
International Operations	193,960	4.1%	936	0.0%	—	0.0%
Natural Gas Storage	65,990	1.4%	95,337	3.0%	99,163	5.6%
Energy Services	3,888,961	81.7%	2,481,566	78.7%	1,125,013	63.5%
Development & Logistics	43,068	0.9%	37,696	1.2%	34,136	1.9%
Intersegment	(63,658)	(1.3%)	(39,257)	(1.2%)	(17,183)	(1.0%)
Total	$ 4,759,610	100.0%	$ 3,151,268	100.0%	$ 1,770,372	100.0%

Pipelines & Terminals Segment

The Pipelines & Terminals segment owns and operates approximately 6,100 miles of pipeline located primarily in the northeastern and upper midwestern portions of the United States and services approximately 110 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 also includes approximately 100 active terminals that provide bulk storage and throughput services with respect to refined petroleum products and renewable fuels, including ethanol, and have an aggregate storage capacity of approximately 37.4 million barrels. Of our terminals in the Pipelines & Terminals segment, over half are connected to our pipelines. We generally own the property on which the terminals are located with the exception of our terminal located in Albany, New York, which is primarily located on leased property. The segment's geographical diversity, connections to multiple sources of supply and extensive delivery system help create a stable base business.

Pipelines

The Pipelines & Terminals segment's pipelines conduct business without the benefit of exclusive franchises from government entities. In addition, the Pipelines & Terminals 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 Pipelines & Terminals 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 Pipelines & Terminals segment is, therefore, subject to a variety of factors partially or entirely beyond our control. Typically, this segment receives 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 presents product volumes and percentage of refined petroleum products transported by the pipelines in the Pipelines & Terminals segment for the periods indicated (volume of barrels per day ("bpd") in thousands):

	Year Ended December 31,					
	2011		2010		2009	
	Volume	Percent	Volume	Percent	Volume	Percent
Gasoline	659.2	48.9%	643.7	49.3%	650.1	49.6%
Jet fuel	340.6	25.3%	338.5	26.0%	336.7	25.7%
Middle distillates (1)	325.5	24.2%	301.3	23.1%	284.7	21.7%
NGLs (2)	—	0.0%	—	0.0%	13.9	1.1%
Other products (3)	22.2	1.6%	21.0	1.6%	24.5	1.9%
Total (4)	1,347.5	100.0%	1,304.5	100.0%	1,309.9	100.0%

(1) Includes diesel fuel, heating oil, kerosene and other middle distillates.
(2) Represents volumes transported by a 350-mile natural gas liquids ("NGL") pipeline that runs from Wattenburg, Colorado to Bushton, Kansas ("Buckeye NGL Pipeline"), which we sold on January 1, 2010.
(3) Includes liquefied petroleum gas ("LPG").
(4) Excludes local product transfers.

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

Pennsylvania—New York—New Jersey. Our operating subsidiary Buckeye Pipe Line Company, L.P. ("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 our operating subsidiary Laurel Pipe Line Company, L.P. ("Laurel") pipeline to Pittsburgh, Pennsylvania (serving Reading, Harrisburg, Altoona/Johnstown, Greensburg 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.

Our operating subsidiary Buckeye Pipe Line Transportation LLC ("BPL Transportation") pipeline system delivers refined petroleum products from a 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 the Paulsboro 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, Greensburg and Pittsburgh, Pennsylvania.

Illinois—Indiana—Michigan—Missouri—Ohio. Buckeye Pipe Line and our operating subsidiary NORCO Pipe Line Company, LLC ("NORCO"), a subsidiary of Buckeye Pipe Line Holdings, L.P. ("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.

Our operating subsidiary Wood River Pipe Lines LLC ("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 the 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.

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. Also, Buckeye Pipe Line owns 650-miles in aggregate of refined product pipeline that originates in Dubuque, Iowa and runs southwest into Missouri and then northwest back into Iowa and other assorted pipelines located in northern Ohio. Buckeye Pipe Line also has a 124-mile pipeline that runs from the South Portland Terminal, in Portland, Maine, to the Bangor Terminal, in Bangor, Maine.

Our operating subsidiary Everglades Pipe Line Company, L.P. ("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.

Our operating subsidiary WesPac Pipelines – Reno LLC ("WesPac Reno") owns an approximately 3-mile pipeline serving the Reno/Tahoe International Airport. Our operating subsidiary WesPac Pipelines – San Diego LLC ("WesPac San Diego") owns an approximately 4-mile pipeline serving the San Diego International Airport. WesPac Pipelines – Memphis LLC ("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, 2011, we had provided $38.4 million in intercompany financing to WesPac Memphis. Each of these entities has been consolidated into our financial statements.

Terminals

The Pipelines & Terminals 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 Pipelines & Terminals 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 Pipelines & Terminals 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 terminals within the Pipelines & Terminals segment for the periods indicated (volume of bpd in thousands):

	Year Ended December 31,		
	2011	2010	2009
Products throughput (1)	742.8	562.5	471.9

(1) Amounts for 2011 include volumes of 199.4 and 13.3 bpd in thousands on terminals acquired from BP and ExxonMobil on June 1, 2011 and July 19, 2011, respectively.

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

Location	Number of Terminals (1)	Storage Capacity (000s Barrels)
Alabama	2	605
California	3	530
Connecticut	1	345
Florida	1	456
Iowa	5	1,302
Illinois	9	3,161
Indiana	11	9,175
Kentucky	1	214
Louisiana	1	135
Maine	1	141
Massachusetts	1	106
Michigan	13	5,370
Missouri	3	1,767
Nevada	1	50
New York	10	4,111
Ohio	14	4,003
Pennsylvania	11	2,536
South Carolina	3	1,022
Tennessee (2)	1	328
Virginia	3	781
Wisconsin	4	1,228
Total	99	37,366

(1) This table includes five terminals, which are owned by the Energy Services segment (as discussed below), in Pennsylvania with aggregate storage capacity of approximately 1.0 million barrels. This table does not include the Yabucoa terminal & BORCO facility that are included in the International Operations segment for reporting purposes (as discussed below) with an aggregate storage capacity of approximately 26.1 million barrels.

(2) This represents the terminal facility owned by WesPac Memphis that primarily serves Federal Express Corporation at the Memphis International Airport. BPH and Kealine each have a 50% ownership interest in WesPac Memphis.

Equity Investments

We own a 34.6% equity interest in West Shore Pipe Line Company ("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%. 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 and crude products to markets in northern Illinois and Wisconsin. The other equity holders of West Shore are affiliated with major oil and gas companies. Since January 1, 2009, we have operated the West Shore pipeline system on behalf of West Shore.

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

Additionally, we own 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.

We also own a 50% equity interest in South Portland Terminal LLC ("South Portland"), which has approximately 725,000 barrels of storage capacity.

In May 2011, we sold our 20% interest in WT LPG to affiliates of Atlas Pipeline Partners L.P. for $85.0 million. WT LPG owns a 2,295-mile common-carrier pipeline system that transports natural gas liquids from points in New Mexico and Texas to Mont Belvieu, Texas for fractionation.

International Operations Segment

The International Operations segment includes 2 marine terminals that provide bulk storage and throughput services with respect to crude oil and petroleum products with an aggregate storage capacity of approximately 26.1 million barrels. The BORCO terminal facility and the Yabucoa terminal facility represent our entry into international marine terminal operations. We own the property on which the BORCO terminal facility is located and lease properties for both the jetty and inland dock operations. The property on which the Yabucoa terminal is located is also leased.

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

Location	Number of Terminals	Storage Capacity (000s Barrels)
Bahamas	1	21,440
Puerto Rico	1	4,623
Total	2	26,063

BORCO Facility

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. Ancillary services provided by BORCO facilitate customer activities within the tank farm and at the jetties.

BORCO's terminal facility includes 80 aboveground storage tanks with a storage capacity of approximately 21.4 million barrels. The existing marine infrastructure of BORCO's terminal facility consists of three deep-water jetties. With recent completion of a refurbishment project on one of the jetties, commissioned in December 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 both very large crude carriers and ultra large crude carriers. BORCO currently has a long term agreement through 2057 with the Bahamas Government to lease 330 acres of seabed on which the jetties are located.

BORCO's terminal facility also includes an inland dock located in Freeport Harbor with two berths. BORCO currently leases the inland dock from the Freeport Harbour Company under a long-term agreement through 2067.

Yabucoa Terminal

The Yabucoa terminal includes 44 storage tanks with approximately 4.6 million barrels of gasoline, jet fuel, diesel, fuel oil and crude oil storage capacity. Access to the Yabucoa terminal is provided through one ship dock and two barge docks as well as an 8-bay truck rack. The docks are leased from the Puerto Rico Port Authority.

Natural Gas Storage Segment

Our operating subsidiary Buckeye Gas Storage LLC, through its subsidiary Lodi Gas Storage, L.L.C. ("Lodi Gas") owns a natural gas facility in Northern California. The natural gas facility currently has approximately 30 Bcf of working natural gas storage and is connected to Pacific Gas and Electric's ("PG&E") 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 PG&E just north of Antioch, California. Six miles of pipeline links the Kirby Hills facility to an interconnect with PG&E 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 natural 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 Energy Services 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 Energy Services segment markets gasoline, propane, ethanol, biodiesel and petroleum distillates such as heating oil, diesel fuel and kerosene. The Energy Services segment owns 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 also 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 millions of gallons):

	Year Ended December 31,		
	2011	2010	2009
Sales volumes	1,337.8	1,139.1	655.1

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; and
- 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.

The operations of the Energy Services segment expose us to commodity price risk. The commodity price risk is managed by entering into derivative instruments to offset the effect of commodity price fluctuations on the segment's inventory and fixed-price 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 managing our market price risk from holding physical inventory and entering into physical fixed-price contracts. A majority of the futures contracts executed are designated as fair value hedges of our refined petroleum inventory. The changes in fair value of the hedge instruments and hedged items are both recognized in cost of product sales. 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 revenue and 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 and natural gas storage services.

Development & Logistics Segment

The Development & Logistics segment operates and maintains approximately 2,800 miles of third-party pipelines under agreements with major oil and gas, petrochemical and chemical companies, which are primarily located in Texas and Louisiana, and perform certain engineering and construction management services for third parties. Development & Logistics also owns and operates two underground propane storage caverns in Huntington, Indiana and Tuscola, Illinois with approximately 800,000 barrels of throughput and storage capability. This segment also owns approximately 25 miles of pipeline located in Texas, a portion of which it leases to a third-party. The Development & Logistics segment also owns an approximate 63% interest in a crude butadiene pipeline in 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 are a key area of focus for the Development & Logistics segment. The segment also operates as an asset and business development service provider for many of its third-party asset owners as well as for other oil and gas, petrochemical and chemical companies.

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 that support distribution growth; and
- We maintain a conservative financial position with an investment-grade credit rating.

Pipelines & Terminals Segment

Generally, pipelines are the lowest cost method for long-haul overland movement of refined petroleum products. Therefore, the Pipelines & Terminals segment's most significant competitors for large volume shipments are other pipelines, some of which are owned or controlled by major integrated oil and gas companies. Although it is unlikely that a pipeline system comparable in size and scope to the Pipelines & Terminals 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 Pipelines & Terminals segment in particular locations.

The Pipelines & Terminals 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. Additionally, the South Portland and Bangor terminals compete with regional barge-supplied terminals.

Trucks competitively deliver refined petroleum products in a number of areas that the Pipelines & Terminals 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 Pipelines & Terminals 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 the 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 Pipelines & Terminals segment's business is largely driven by the consumption of fuel in its delivery areas and the Pipelines & Terminals segment's 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 Pipelines & Terminals segment. As discussed in "Item 1A, Risk Factors", a significant decline in production at the Wood River refinery, Paulsboro refinery or Lima refinery, or a fundamental change in the primary sources or supply of petroleum products to a region, could materially impact the business of the Pipelines & Terminals segment.

The Pipelines & Terminals segment also generally competes with other terminals in the same geographic market. Many competitive terminals are owned by major integrated oil and gas companies. These major oil and gas companies may have the opportunity for product exchanges that are not available to the Pipelines & Terminals segment's terminals. While the

Pipelines & Terminals 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 gasoline stations.

International Operations Segment

Our facility in Yabucoa, Puerto Rico faces competition for residual fuel oil storage as a result of the method by which the local utility company, which is a significant fuel oil user, sources fuel for their power generation needs.

Our facility in Freeport, Bahamas faces competition with some proprietary and third party independent terminal operators in the Caribbean region. The facility's location, deep draft coupled with its storage and blending capability provides certain advantages to our customers for export of products 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 adds competition for handling of remaining product demand into certain areas.

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 and gas 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.

Development & Logistics Segment

The Development & Logistics segment competes with independent pipeline companies, engineering firms, major integrated oil and gas 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, 2011, 2010 and 2009, no customer contributed 10% or more of our consolidated revenue.

Seasonality

The Pipelines & Terminals segment's 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, this segment's business has 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 International Operations segment's mix and volume of products stored during the year does not significantly vary considering the multi-year contracts that provide cash flow stability.

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 quarters' 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, 2011, Services Company had approximately 1,029 full-time employees, 181 of whom were represented by seven labor unions. At December 31, 2011, approximately 21 individuals were employed directly by Lodi Gas, 16 individuals were employed directly by a subsidiary of BPH and 20 individuals were directly employed by our operating subsidiary Buckeye Caribbean Holdings Limited ("Buckeye Caribbean Terminals LLC"). We reimburse Services Company for the cost of providing those employee services pursuant to a services agreement. Additionally, BORCO employs a non-union workforce that consisted of approximately 157 full-time individuals at December 31, 2011. 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 "Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources."

During 2011, we spent approximately $305.3 million for capital expenditures, of which $57.4 million related to sustaining capital projects and $247.9 million related to expansion and cost reduction projects. Expansion and cost reduction projects included upgrades and expansions of a jetty structure and inland dock at BORCO, terminal ethanol and butane blending, new pipeline connections, continued progress on a new pipeline and terminal billing system as well as various other operating infrastructure projects.

We expect to spend approximately $250.0 million to $330.0 million for capital expenditures in 2012, of which approximately $50.0 million to $70.0 million is expected to relate to sustaining capital expenditures and $200.0 million to $260.0 million is expected to relate to expansion and cost reduction projects. Approximately $130.0 million to $180.0 million of these amounts are related to capital expenditures in 2012 for the BORCO facility, of which $120.0 million to $160.0 million is expected to relate to expansion projects and $10.0 million to $20.0 million is expected to relate to sustaining capital expenditures. Approximately $120.0 million to $150.0 million of these amounts are related to capital expenditures in 2012 for our other assets, excluding the BORCO facility, of which $80.0 million to $100.0 million is expected to relate to expansion projects and $40.0 million to $50.0 million is expected to relate to sustaining capital expenditures. 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 2012 will include terminal storage tank expansion projects at the BORCO facility, completion of additional storage tanks and rail loading facilities in the Midwest, the refurbishment of storage tanks and facilities in the Northeast, continued installation of vapor recovery units throughout our system of terminals, additive system installation throughout our terminal infrastructure and various upgrades and expansions of our ethanol business. Cost reduction expenditures improve operational efficiencies or reduce costs.

Regulation

General

We are subject to extensive laws and regulations and resulting 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 and natural gas storage industries, 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 business and 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 that FERC believes reflects cost changes appropriate for application to pipeline rates. In December 2010, FERC amended its regulations to change the index to the Producer Price Index – finished goods ("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 California Public Utilities Commission ("CPUC"). 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 and its Certificate of Public Convenience and Necessity, 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 may incur material environmental liabilities in the future. 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 significant current environmental laws and regulations to which our business operations are subject and for which compliance may require material capital expenditures 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 and terminalling 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 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 and terminal 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 currently imposed on us are being reviewed by 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 which could have a material adverse effect on our maintenance capital expenditures and operating expenses. In addition, certain states (primarily California) and regions have considered various GHG regulations which may add controls separate from or in conjunction with federal 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 and the Hazardous Liquid Pipeline Safety Act of 1979. Since the passage of these safety statutes, the resulting DOT regulations have been modified and strengthened by various Congressional actions including the Pipeline Safety Reauthorization Act of 1988, the Pipeline Safety Act of 1992, the Accountable Pipeline Safety and Partnership Act of 1996, the Pipeline Safety Improvement Act of 2002, the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 and the most recent Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. These Acts and the resulting DOT regulations govern the design, installation, testing, construction, operation, replacement and management of pipeline facilities and require any entity that owns or operates pipeline facilities to comply with applicable safety standards, to establish and maintain plans of inspection and maintenance and integrity management program and to comply with such plans and programs. Also governed by the Acts and related regulations are requirements for a drug and alcohol testing program, an Operator Qualification program that ensures that persons performing tasks covered by the pipeline safety rules are qualified, a public education program for residents, public officials, emergency responders and contractors.

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

The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 ("PSA 2011") was signed into law on January 3, 2012. This law has a number of provisions that will either directly or potentially impact the oil and gas industry. PSA 2011 strengthens damage prevention regulations and provides authority to further strengthen such regulations with respect to High Consequence Areas ("HCAs") in the future. Similarly, PSA 2011 requires that PHMSA conduct a number of evaluations and studies and, based on the results, promulgate regulations to address possible expansion of the integrity management requirements to areas outside of HCAs; changes to operators' public education programs to increase outreach to the affected public; the technical limitations and practicality of requiring the use of leak detection systems and the standards relating thereto; and incidents that may have been caused by lack of adequate depth of cover at water crossings of 100 feet or more. PSA 2011 also specifically requires PHMSA to establish time limits for reporting incidents to the National Response Center as well as coordination of notifications to state/local first responders and issue regulations to improve the current administrative enforcement process for pipeline operators. PSA 2011 increases penalties for non-compliance with PHMSA regulations from a $100,000 to a $200,000 maximum for a single violation, and from a $1.0 million to a $2.0 million maximum for a series of violations.

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.

Environmental Hazards and Insurance

Our business involves a variety of risks, including the risk of natural disasters, adverse weather, fire, explosions, and equipment failures, any of which could lead to environmental hazards such as petroleum product spills and other releases. If any of these should occur, we could incur legal defense costs and environmental remediation costs, and could be required to pay amounts due to injury, loss of life, damage or destruction to property, natural resources and equipment, pollution or environmental damage, regulatory investigation and penalties and suspension of operations.

We are covered by site pollution incident legal liability insurance policies with per incident and aggregate limits of $100 million, subject to a maximum self-insured retention of $4.5 million. The policies include coverage for sudden and accidental or gradual releases at our listed sites. The policies also include a contractor's pollution coverage endorsement. The insurance policies expire on September 30, 2012. The policies insure (i) claims, remediation costs, and associated legal defense expenses for pollution conditions at, or migrating from, a covered location, and (ii) the transportation risks associated with moving waste from a covered location to any location for unloading or depositing waste. The premises pollution liability policies contain exclusions, conditions, and limitations that could apply to a particular pollution claim, and may not cover all claims or liabilities we incur.

In addition to the site pollution incident legal liability insurance policies, we maintain casualty insurance policies with aggregate and per occurrence limits of $400.0 million, subject to a maximum self-insured retention of $25.0 million. The policies provide coverage for claims involving sudden and accidental releases. Coverage under the casualty insurance is secondary to the site pollution incident legal liability policies for sudden and accidental releases. The insurance policies expire on September 30, 2012. The pollution coverage provided in the casualty insurance policies contains exclusions, definitions, conditions and limitations that could apply to a particular pollution claim, and may not cover all claims or liabilities we incur.

We generally are not entitled to seek indemnification from our contractual counterparties for any environmental damage caused by the release of products we store, throughput or transport for such counterparties. As discussed above, we maintain insurance policies that are designed to mitigate the risk that we may incur costs and losses in connection with any such release of products from our facilities, and we believe that the policy limits under site pollution incident legal liability and casualty insurance policies are within the range that is customary for companies of our size that operate in our business segments and are appropriate for our business.

We attempt to reduce our exposure to third party liability by requiring indemnification and access to third party insurance from our contractors or entities who require access to our facilities and our right of way. We have requirements for limits of insurance provided by third parties which we believe are in accordance with industry standards and proof of third party insurance documentation is retained prior to commencement of work.

We have written plans for responding to emergencies along our pipeline system and at our terminal facilities. These plans which describe the organization, responsibilities and actions for responding to emergencies are reviewed annually and updated as necessary. Our facilities are designed with product containment structures, and we maintain various additional oil containment and recovery equipment that would be deployed in the event of an emergency. We are a member of ten oil spill cooperatives or mutual aid groups. We maintain more than 50 contract relationships with United States Coast Guard certified oil spill response organizations, spill response contractors and remediation management consultants. This ensures access to spill response equipment (including boom, recovery pumps, response vehicles, response vessels and response trailers), monitoring and sampling equipment, personal protective equipment and technical expertise needed to respond to an emergency event. We also perform spill response drills to review and exercise the response capabilities of our personnel, contractors and emergency management agencies. Additionally, we have a Crisis Management Team within our organization to provide strategic direction, ensure availability of company resources and manage communications in the event of an emergency situation.

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 Pipelines & Terminals 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 Pipelines & Terminals 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. Additionally, the South Portland to Bangor pipeline terminal is mainly supplied by overseas ships from Canada and Europe.

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 Pipelines & Terminals 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 major integrated oil companies, their marketing affiliates, and independent brokers and marketers of widely varying sizes, financial resources and experience. Some of these companies have superior access to capital resources, which could affect our ability to effectively compete with them.

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

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

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

We are a holding company and depend entirely on our operating subsidiaries' distributions to service our debt obligations and pay cash distributions to our unitholders.

We are a holding company with no material operations. If we do not receive cash distributions from our operating subsidiaries, we will not be able to meet our debt service obligations or to make cash distributions to our unitholders. Among other things, this would adversely affect the market price of our LP Units. We are currently bound by the terms of 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 operated as a refinery until it was shut down in 1985. We performed a certain level of diligence in connection with the acquisition of BORCO and attempted to ascertain the extent of liabilities that might be associated with the facility, but there may be unknown and contingent liabilities related to BORCO of which we are unaware.

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, or a fundamental change in the primary source of supply of petroleum products to a region, could materially reduce the volume of refined petroleum products we transport and adversely impact our operating results.

Refineries that our pipelines and terminals service could partially or completely shut down their 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 Wood River refinery, Paulsboro refinery or Lima refinery could negatively impact the financial performance of such assets and adversely affect our business, financial position, results of operations or cash flows.

In addition, if there is a fundamental shift in the primary source of supply of petroleum products to a region our pipelines serve and our pipeline infrastructure in the region is not well-suited to serve the new primary source, the performance of such assets could be negatively impacted, and adversely affect our business, financial position, results of operations and 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 revenue relates 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, including to connect or integrate their operations with those of our existing assets. If we consummate any future acquisitions, our capitalization and results of operations may change significantly.

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

Debt securities we issue are, and will continue to be, junior to claims of our operating subsidiaries' creditors.

Our outstanding debt securities are structurally subordinated to the claims of our operating subsidiaries' creditors. In addition, any debt securities we issue in the future will likewise be subordinated in the same manner.

Holders of the debt securities will not be creditors of our operating subsidiaries. Our claim to the assets of our operating subsidiaries derives from our own ownership interests in those operating subsidiaries. Claims of our operating subsidiaries' creditors will generally have priority as to the assets of our operating subsidiaries over our own ownership interests and will therefore have priority over the holders of our debt, including our debt securities.

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

Buckeye Pipe Line, Wood River, BPL Transportation and NORCO are interstate common carriers regulated by the FERC under the Interstate Commerce Act, 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. 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, on its own initiative or as the result of a complaint, 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" ("GHG") 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 may require reporting for some of our facilities in future years. Furthermore, the EPA has issued a final rule setting emission standards for light-duty vehicles for the 2012-2016 model years. On September 15, 2011, the EPA implemented 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 now requires construction and operating permits for very large GHG emissions sources. The EPA now requires GHG emissions estimates be provided in almost all construction and operating air permit applications.

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 GHG from our equipment and operations or any future laws or regulations that may be adopted to address GHG emissions could require us to incur costs to reduce emissions of GHG 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 GHG emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a GHG 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 GHG 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 effect 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. In addition, any new regulations that are the result of PSA 2011 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.

The Natural Gas Storage segment offers interruptible storage services to customers, which allow customers to borrow gas from our storage facilities. In the event a customer does not repay its loan in-kind with physical natural gas, we would be required to enter the physical natural gas markets to procure the volumes borrowed from the facility in order to honor our commitments to our other storage customers. A customer's nonperformance under an interruptible storage agreement or failure to keep us financially whole 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 year ended December 31, 2011. 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 year ended December 31, 2011, approximately 27% and 58% 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.

Terrorist attacks or other security threats 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. In addition to the threat of terrors attacks, we face various other security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the safety of our employees; threats to the security of our facilities, such as terminals and pipelines, and infrastructure or third party facilities and infrastructure. These developments have subjected our operations to increased risks.

Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to security threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities, essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows. Cybersecurity attacks in particular are evolving and include but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. These events could damage our reputation and lead to financial losses from remedial actions, loss of business or potential liability.

During 2007, the Department of Homeland Security promulgated the Chemical Facility Anti-Terrorism Standards ("CFATS") to regulate the security of facilities that handle certain 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, which continued in 2011 and 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.

In addition to CFATS, our domestic operations are also subject to other laws and regulations promulgated and enforced by other components of the Department of Homeland Security and the Department of Transportation. Our operations in the Bahamas are subject to similar security-related regulations. We believe that we currently comply in all material respects with security-related laws and regulations. However, this is an area of continued regulatory developments for our industry and as such, we may incur increased operating costs based on developments associated with these regulations. At this time, we do not believe that future compliance with these requirements 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 or entitled to indemnification.

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. Further, our environmental pollution coverage is subject to exclusions, conditions and limitations that could apply to a particular pollution claim or may not cover all claims or liabilities we incur. The contracts with our customers and other business partners involve risk-allocation and indemnification provisions. However, pursuant to these contracts we generally may not seek indemnification from a counterparty for liabilities, including those associated with the release of petroleum products, arising at a time in which we are in possession of the product owned by the counterparty. If we were to incur a significant liability for which we were not fully insured, or insured at all, 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 and other severe weather conditions could damage our 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 our facilities, in particular our BORCO facility or Yabucoa terminal, could be impacted by severe weather conditions, including hurricanes. Any such event could cause a serious business disruption or serious damage to our facilities, which could affect such facilities' ability to provide services. Additionally, such events could impact our 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.

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

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 moderate, our business, financial condition, results of operations, or cash flows could be negatively impacted due to a lack of demand for storage capacity. In addition, a material change in the supply of, or demand for, natural gas could negatively impact the value of lease capacity and hub services activities, which could adversely affect our results of operations.

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. Factors that could cause significant increases or decreases in commodity prices include changes in supply due to production constraints, weather, governmental regulations, and changes in consumer demand. 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 price 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 enter into financial hedges that are priced at a certain location, such as New York Harbor, but the sales or exchanges of the underlying commodity are 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.

We could be adversely affected by violations of the U.S. Foreign Corrupt Practices Act and similar worldwide anti-bribery laws.

Our international operations require us to comply with a number of U.S. and international laws and regulations, including those involving anti-bribery and anti-corruption. For example, the U.S. Foreign Corrupt Practices Act and similar international laws and regulations prohibit improper payments to foreign officials for the purpose of obtaining or retaining business. The scope and enforcement of anti-corruption laws and regulations may vary.

We operate in parts of the world that have experienced governmental corruption to some degree and, in certain circumstances, strict compliance with anti-bribery laws may conflict with local customs and practices. Our compliance programs and internal control policies and procedures may not always protect us from reckless or negligent acts committed by our employees or agents. Violations of these laws, or allegations of such violations, could disrupt our business and result in a material adverse effect on our business and operations.

Our pending acquisition of the Perth Amboy Facility may not be consummated.

Our pending acquisition of the Perth Amboy Facility is expected to close in the second quarter of 2012 and is subject to closing conditions and regulatory approvals. If these conditions and regulatory approvals are not satisfied or waived, the acquisition will not be consummated. If the closing of the acquisition is substantially delayed or does not occur at all, or if the terms of the acquisition are required to be modified substantially due to regulatory concerns, we may not realize the anticipated benefits of the acquisition fully or at all. Certain of the conditions remaining to be satisfied include:

- the issuance by the United States Environmental Protection Agency of an amended hazardous and solid waste permit (the "HSWA Permit") on terms satisfactory to Chevron in its sole discretion;
- the grant of a legal subdivision of certain real property to be retained by Chevron;
- the absence of any damage to, or destruction or condemnation of, the assets subject to the Purchase and Sale Agreement ("P&SA") which reduces the economic value of such assets by $20,000,000 or more (a "Material Adverse Change"); or, if any Material Adverse Change has occurred, the cure or other mutually agreeable resolution thereof;
- the absence of certain factual discoveries by us of certain matters relating to title, environmental liabilities or regulatory obstacles which reduce the economic value of the assets subject to the P&SA by $20,000,000 or more, subject to certain exclusions (a "Material Discovery"); or, if any Material Discovery has occurred, the cure or other mutually agreeable resolution thereof; and
- the absence of any pending or threatened litigation or administrative proceeding, or any pending investigation, by any party or any third party seeking to restrain or prohibit (or questioning the validity or legality of) the consummation of the transactions contemplated by the P&SA or seeking damages in connection therewith which makes it unreasonable to proceed with the consummation of the transactions contemplated thereby.

In addition, the P&SA may be terminated by mutual agreement of the parties thereto or as follows (i) by either Chevron or us, if the acquisition has not closed on or before June 30, 2012; provided, however that if the HSWA Permit has not been released for public comment on or before March 31, 2012, then Chevron shall not have the right to terminate the P&SA unless the acquisition has not closed on or before July 31, 2012 (in each case, subject to a 30-day extension to give effect to certain cure periods), (ii) by either Chevron or us, if the other party has materially breached its obligations under the P&SA, which breaches have not been cured within the applicable time frame or that by their nature cannot be cured, (iii) by either Chevron or us, if any statute, rule or regulation makes consummation of the acquisition illegal or otherwise prohibited, or if any order, decree, ruling or other action by any governmental authority permanently restraining, enjoining or otherwise prohibiting the consummation of the acquisition has become final and non-appealable, (iv) by Chevron, if us conducts internal inspections of out of service tanks on the Facility, retains or utilizes the services of a New Jersey licensed site remediation professional or has any communications with any governmental authority with respect to the assets subject to the P&SA (other than pursuant to the Hart Scott Rodino Act or solely in anticipation of the transfer of the assets to us at the closing), (v) by us, upon the occurrence of a Material Discovery or a Material Adverse Change, subject to certain cure rights of Chevron, (vi) by Chevron, upon its reasonable determination that a Material Discovery relating to environmental liabilities cannot be cured or remediated using reasonable methods or resources, (vii) by either Chevron or us, upon the occurrence of certain damage to, or destruction or condemnation of, the assets subject to the P&SA not constituting a Material Adverse Change, subject to certain cure rights of Chevron, and (viii) by Chevron, if it determines in its sole discretion that the HSWA Permit is not satisfactory.

Increases in interest rates could adversely affect our unit price.

Interest rates on future debt offerings could be higher than current levels, causing our financing costs to increase accordingly. An increase in interest rates could also cause a corresponding decline in demand for equity investments, in general, and in particular for yield-based equity investments such as our LP Units. Lower demand for our LP Units for any reason, including competition from other more attractive investment opportunities, would likely cause the trading price of our LP Units to decline. If we issue additional equity at a significantly lower price, material dilution to our existing unitholders could result.

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

Our Energy Services and Natural Gas Storage segments follow risk management practices that are designed to minimize commodity price risk, credit risk and operational risk for their respective 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.

Increases in interest rates could adversely affect our business and the trading price of our units.

We use both fixed and variable rate debt, and we are exposed to market risk due to the floating interest rates on our credit facility. From time to time we use interest rate derivatives to hedge interest obligations on specific debt. In addition, interest rates on future debt offerings could be higher, causing our financing costs to increase accordingly. Our results of operations, cash flows and financial position could be adversely affected by significant increases in interest rates above current levels. Additionally, the trading price of our limited partnership units may be sensitive to changes in interest rates and any rise in interest rates could adversely impact such trading price.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act"), was signed into law by the President on July 21, 2010 and requires the U.S. Commodity Futures Trading Commission (the "CFTC"), the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In December 2011, the CFTC extended temporary exemptive relief from certain swap regulation provisions of the legislation until July 16, 2012. In its rulemaking under the Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions or derivative instruments would be exempt from these position limits. It is not possible at this time to predict when the CFTC will make these regulations effective. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Any of these consequences could have a material, adverse effect on us, our financial condition, and our results of operations.

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.

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 results from that income.

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

If you sell your LP Units, you will recognize a gain or loss equal to the difference between the amount 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 individual retirement accounts ("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 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.

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 49,000 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, Business" 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***

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

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

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

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

In 2010, the Attorney General of Illinois and the State's Attorney for Will County, Illinois, filed a complaint under caption the People of the State of Illinois et al v. Buckeye Pipe Line Company, L.P. et al. in connection with an alleged release of oil on December 14, 2010, from a pipeline owned by West Shore and operated by Buckeye Pipe Line in Lockport, Illinois. The parties are close to finalizing a settlement for the litigation, and at this time, we anticipate entry of a settlement order by the Court in the first or second quarter of 2012 with the aggregate penalty amount for both West Shore and Buckeye Pipe Line marginally exceeding $0.1 million. Any penalty amount will be paid by West Shore pursuant to the terms of the operating agreement.

Item 4. *Mine Safety Disclosures*

Not applicable.

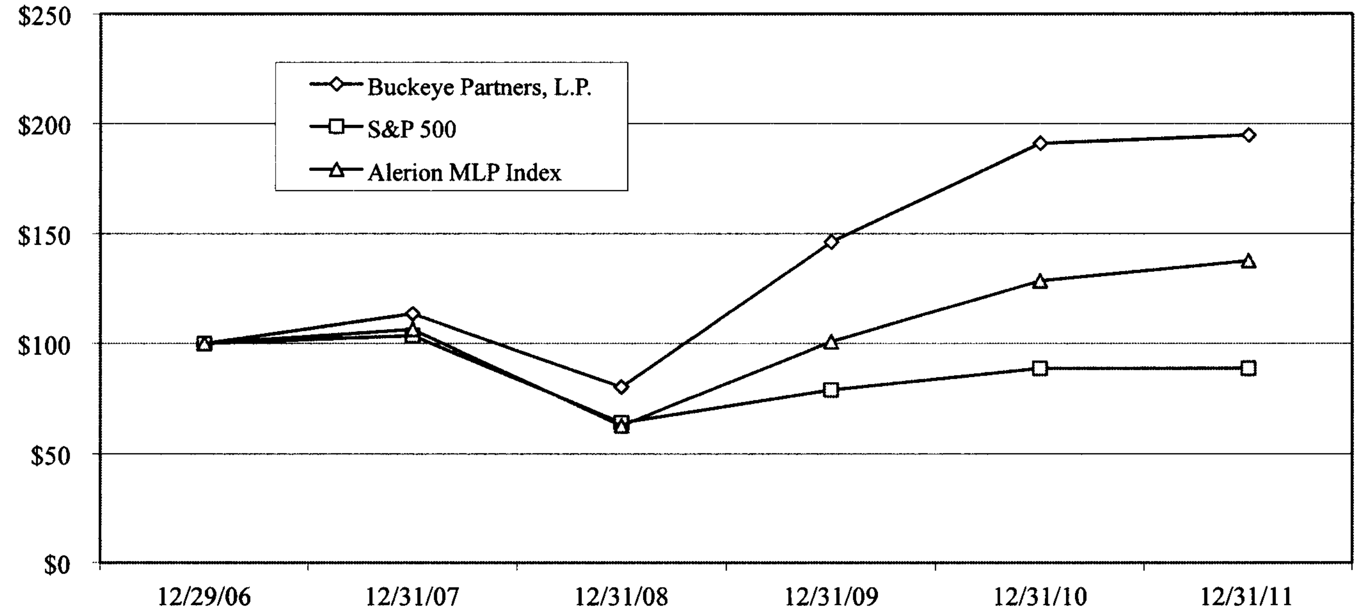
PART II

Item 5. *Market for the Registrant's Units, Related Unitholder Matters, and Issuer Purchases of 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, 2011 and 2010, as reported in the NYSE Composite Transactions, were as follows:

	2011		2010	
Quarter	**High**	**Low**	**High**	**Low**
First	$ 68.81	$ 58.45	$ 61.50	$ 51.68
Second	65.20	59.85	62.39	45.00
Third	65.24	54.51	66.00	57.19
Fourth	68.45	59.00	71.67	62.00

The following graph compares the total unitholder return performance of our LP Units with the performance of (i) the Standard & Poor's 500 Stock Index ("S&P 500") and (ii) the Alerian MLP index. The Alerian MLP Index is a composite of the 50 most prominent energy master limited partnerships that provides investors with a comprehensive benchmark for this asset class. The graph assumes that $100 was invested in our LP Units and each comparison index beginning on December 29, 2006 and that all distributions or dividends were reinvested on a quarterly basis.



	12/29/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011
Buckeye Partners, L.P.	$ 100.00	$ 113.40	$ 80.01	$ 146.27	$ 191.07	$ 194.75
S&P 500	$ 100.00	$ 103.55	$ 63.70	$ 78.64	$ 88.69	$ 88.69
Alerian MLP Index	$ 100.00	$ 106.43	$ 62.31	$ 100.87	$ 128.54	$ 137.82

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 133,629 at December 31, 2011.

There is no established trading market for our Class B Units. As of December 31, 2011, our Class B Units were held by 10 holders of record.

Cash distributions paid to LP Unitholders for the periods indicated were as follows:

Record Date	Payment Date	Amount Per LP Units
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
February 21, 2011	February 28, 2011	$ 0.9875
May 16, 2011	May 31, 2011	1.0000
August 15, 2011	August 31, 2011	1.0125
November 14, 2011	November 30, 2011	1.0250

On February 10, 2012, we announced a quarterly distribution of $1.0375 per LP Unit that will be paid on February 29, 2012, to unitholders of record on February 21, 2012. Total cash distributed to LP Unitholders on February 29, 2012 will be approximately $89.5 million. Class B Unitholders will not receive a distribution of cash, 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

None.

Item 6. *Selected Financial Data*

The following tables set forth, for the periods and at the dates indicated, our selected consolidated financial data for each of the last five years which 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 unit amounts).

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.

	Year Ended December 31,				
	2011 (1)	2010	2009	2008 (1)	2007
Income Statement Data:					
Revenue	$ 4,759,610	$ 3,151,268	$ 1,770,372	$ 1,896,652	$ 519,347
Depreciation and amortization	119,534	59,590	54,699	50,834	40,236
Equity plan modification expense (2)	—	21,058	—	—	—
Goodwill impairment expense (2)	169,560	—	—	—	—
Asset impairment expense (2)	—	—	59,724	—	—
Reorgnization expense (2)	—	—	32,057	—	—
Operating income (2)	188,874	279,501	203,800	246,492	195,353
Interest and debt expense	119,561	89,169	75,147	75,410	51,721
Net income (2)	114,664	201,008	141,637	180,623	152,675
Net income attributable to noncontrolling interests (3)	(6,163)	(157,928)	(92,043)	(154,146)	(129,754)
Net income attributable to Buckeye Partners, L.P.	108,501	43,080	49,594	26,477	22,921
Earnings per unit - diluted (4)	$ 1.20	$ 1.65	$ 2.49	$ 1.33	$ 1.15
Cash distributions per LP Unit - paid	$ 4.03	$ 3.83	$ 3.63	$ 3.43	$ 3.23

	December 31,				
	2011 (1)	2010	2009	2008 (1)	2007
Balance Sheet Data:					
Total assets	$ 5,570,376	$ 3,574,216	$ 3,486,571	$ 3,263,097	$ 2,354,326
Total debt, including current portion	2,644,774	1,805,218	1,746,473	1,555,719	869,463
Total Buckeye Partners, L.P. capital (3)	2,303,169	1,392,405	242,334	232,060	238,330
Accumulated other comprehensive loss (3)	(127,741)	(21,259)	—	—	—
Noncontrolling interests (3)	20,788	17,855	1,209,960	1,166,774	1,066,143

(1) Substantial increase in revenue for the year ended December 31, 2011 compared to the year ended December 31, 2010 was the result of the BORCO acquisition in the first quarter of 2011, pipelines and terminals acquired in the second quarter of 2011 and a full year of revenue from the Yabucoa terminal, which was acquired in December 2010. Also, increase in total assets and depreciation and amortization for the year ended December 31, 2011 compared to the year ended December 31, 2010 was a result of the previously noted acquisitions. Substantial increases in revenue, operating income, net income and total assets for the year ended December 31, 2008 compared to the year ended December 31, 2007 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 years ended December 31, 2011, December 31, 2010 and December 31, 2009 include non-cash charges of $169.6 million related to a goodwill impairment (see Note 9 in the Notes to Consolidated Financial Statements), $21.1 million related to the modification of an equity compensation plan (see Note 18 in the Notes to Consolidated Financial Statements) and $59.7 million related to an asset impairment (see Note 7 in the Notes to Consolidated Financial Statements) and $32.1 million of expenses incurred in connection with an organizational restructuring (see Note 23 in the Notes to Consolidated Financial Statements), respectively.

(3) Prior to the Merger, noncontrolling interests reported by BGH included equity interests in Buckeye that were not owned by BGH and amounts in accumulated other comprehensive loss were included in noncontrolling interests. In connection with the Merger, total Buckeye capital increased substantially with the elimination of noncontrolling interests and 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) 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.

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

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

Overview of Business

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

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 6,100 miles of pipeline and over 100 active products terminals that provide aggregate storage capacity of approximately 64 million barrels. We also operate and maintain approximately 2,800 miles of third-party 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 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. Our flagship marine terminal in The Bahamas, BORCO, is one of the largest marine crude oil and petroleum products storage facilities in the world, serving the international markets as a premier global logistics hub.

We operate and report in five business segments: (i) Pipelines & Terminals; (ii) International Operations; (iii) Natural Gas Storage; (iv) Energy Services; and (v) Development & Logistics. See Note 25 in the Notes to Consolidated Financial Statements for a more detailed discussion of our business segments.

Although titled Buckeye Partners, L.P., the accompanying financial statements in this Report were originally the financial statements of BGH prior to the completion of the Merger.

2011 Developments

During 2011, we issued equity and debt, which financed acquisitions and expansion projects. During January and February 2011, we completed the purchase of First Reserve's and Vopak's interests in FRBCH for approximately $1.4 billion in cash and equity and repaid BORCO's outstanding indebtedness and settled their interest rate derivative instruments, collectively representing approximately $318.2 million. To fund a portion of the acquisition, we issued $650.0 million of our 4.875% Notes due 2021 and issued 5,794,725 LP Units and 1,314,870 Class B Units to institutional investors for aggregate consideration of approximately $425.0 million. Also, we issued 2,483,444 LP Units and 4,382,889 Class B Units to First Reserve as $400.0 million of consideration and 620,861 LP Units and 1,095,722 Class B Units to Vopak as $100.0 million of consideration. In April 2011, we issued 5,520,000 LP Units in an underwritten public offering with net proceeds of $316.6 million. In May 2011, we sold our 20% interest in WT LPG for $85.0 million. Then, in June 2011, we acquired pipeline and terminal assets from BP for $166.0 million, and in July 2011, we acquired a terminal in Bangor, Maine, a terminal in Portland, Maine through a 50/50 joint venture with Irving and a 124-mile pipeline that connects the two terminals from ExxonMobil for $23.5 million. In September 2011, Buckeye and Buckeye Energy Services LLC ("BES") entered into a Credit Facility with SunTrust Bank and other lenders to provide for a $1.25 billion senior unsecured revolving credit agreement.

Results of Operations

Consolidated Summary

Adjusted EBITDA (as defined below) increased during the year ended December 31, 2011 compared to the year ended December 31, 2010 and during the year ended December 31, 2010 compared to the year ended December 31, 2009.

Our revenue increased during the year ended December 31, 2011 compared to the year ended December 31, 2010, primarily due to an overall increase in refined petroleum product prices and volumes of products sold in the Energy Services segment, the BORCO acquisition and a full year of revenue from the Yabucoa terminal in the International Operations segment, acquisitions in 2011 and 2010 and higher pipeline tariff rates and terminalling fees in the Pipelines & Terminals segment, partially offset by lower volumes on legacy assets in the Pipelines & Terminals segment. Our operating income and net income decreased during the year ended December 31, 2011 compared to the year ended December 31, 2010, primarily due to recognition of a goodwill impairment in the Natural Gas Storage segment.

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

	Year Ended December 31,		
	2011	2010	2009
Revenue	$ 4,759,610	$ 3,151,268	$ 1,770,372
Costs and expenses	4,570,736	2,871,767	1,566,572
Operating income	188,874	279,501	203,800
Earnings from equity investments	10,434	11,363	12,531
Gain on sale of equity investment	34,727	—	—
Interest and debt expense	(119,561)	(89,169)	(75,147)
Other income (expense)	190	(687)	453
Net income	114,664	201,008	141,637
Less: net income attributable to noncontrolling interests	(6,163)	(157,928)	(92,043)
Net income attributable to Buckeye Partners, L.P.	$ 108,501	$ 43,080	$ 49,594
Earnings per unit - diluted (1)	$ 1.20	$ 1.65	$ 2.49

(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 U.S. generally accepted accounting principles ("GAAP"), as net income attributable to our unitholders before interest and debt expense, income taxes and depreciation and amortization. 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) non-cash impairment expense related to the Buckeye NGL Pipeline; (iv) organizational restructuring expense; (v) non-cash BGH GP equity plan modification expense; (vi) income attributable to noncontrolling interests related to Buckeye for periods prior to the Merger in order to provide comparability between periods before and after the Merger; and (vii) non-cash goodwill impairment expense associated with the Natural Gas Storage segment; less (i) amortization of unfavorable storage contracts acquired in connection with the BORCO acquisition; and (ii) gain on the sale of our equity investment in WT LPG.

The EBITDA and Adjusted EBITDA data presented may not be comparable to similarly titled measures at other companies because EBITDA and Adjusted EBITDA exclude some items that affect net income 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 our measurement of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income attributable to our unitholders, which is the most comparable GAAP financial measure (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Adjusted EBITDA:			
Pipelines & Terminals	$ 361,018	$ 346,447	$ 302,164
International Operations	112,996	(4,655)	—
Natural Gas Storage	4,204	29,794	41,950
Energy Services	1,797	5,861	19,335
Development & Logistics	7,932	5,193	6,718
Total Adjusted EBITDA	487,947	382,640	370,167
Interest and debt expense	(119,561)	(89,169)	(75,147)
Income tax benefit	192	919	343
Depreciation and amortization	(119,534)	(59,590)	(54,699)
Net income attributable to noncontrolling interests affected by Merger (for periods prior to Merger) (1)	—	(157,467)	(90,381)
Non-cash deferred lease expense	(4,122)	(4,235)	(4,500)
Non-cash unit-based compensation expense	(9,150)	(8,960)	(4,408)
Equity plan modification expense	—	(21,058)	—
Asset impairment expense	—	—	(59,724)
Goodwill impairment expense	(169,560)	—	—
Gain on sale of equity investment	34,727	—	—
Amortization of unfavorable storage contracts	7,562	—	—
Reorganization expense	—	—	(32,057)
Net income attributable to Buckeye Partners, L.P.	108,501	43,080	49,594
Add: net income attributable to noncontrolling interests	6,163	157,928	92,043
Net income	$ 114,664	$ 201,008	$ 141,637

(1) Amounts represent portions of BGH's noncontrolling interests related to Buckeye that were eliminated as a result of the Merger. Amounts are excluded for the portion of 2010 prior to the Merger and the 2009 periods for comparability purposes.

Segment Results

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

	Year Ended December 31,		
	2011	2010	2009
Revenue:			
Pipelines & Terminals	$ 631,289	$ 574,990	$ 529,243
International Operations	193,960	936	—
Natural Gas Storage	65,990	95,337	99,163
Energy Services	3,888,961	2,481,566	1,125,013
Development & Logistics	43,068	37,696	34,136
Intersegment	(63,658)	(39,257)	(17,183)
Total revenue	$ 4,759,610	$ 3,151,268	$ 1,770,372
Total costs and expenses: (1)			
Pipelines & Terminals	$ 340,716	$ 308,806	$ 374,202
International Operations	121,893	5,592	—
Natural Gas Storage	243,153	79,268	68,589
Energy Services	3,893,423	2,482,933	1,111,927
Development & Logistics	35,209	34,425	29,037
Intersegment	(63,658)	(39,257)	(17,183)
Total costs and expenses	$ 4,570,736	$ 2,871,767	$ 1,566,572
Depreciation and amortization:			
Pipelines & Terminals	$ 55,469	$ 46,320	$ 42,791
International Operations	50,011	—	—
Natural Gas Storage	7,136	6,594	5,971
Energy Services	5,261	4,933	4,204
Development & Logistics	1,657	1,743	1,733
Total depreciation and amortization	$ 119,534	$ 59,590	$ 54,699
Operating income (loss):			
Pipelines & Terminals	$ 290,573	$ 266,184	$ 155,041
International Operations	72,067	(4,656)	—
Natural Gas Storage	(177,163)	16,069	30,574
Energy Services	(4,462)	(1,367)	13,086
Development & Logistics	7,859	3,271	5,099
Total operating income	$ 188,874	$ 279,501	$ 203,800

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

The following table presents product volumes transported and average daily throughput for the Pipelines & Terminals segment and total volumes sold for the Energy Services segment for the periods indicated:

	Year Ended December 31,		
	2011	2010	2009
Pipelines & Terminals (average bpd in thousands):			
Pipelines:			
Gasoline	659.2	643.7	650.1
Jet fuel	340.6	338.5	336.7
Diesel fuel	264.3	234.4	209.8
Heating oil	61.2	66.9	74.9
LPGs	16.2	18.0	16.5
NGLs (1)	—	—	13.9
Other products	6.0	3.0	8.0
Total pipelines throughput	1,347.5	1,304.5	1,309.9
Terminals:			
Products throughput (2)	742.8	562.5	471.9
Energy Services (in millions of gallons):			
Sales volumes	1,337.8	1,139.1	655.1

(1) Represents volumes transported by the Buckeye NGL Pipeline, which we sold on January 1, 2010.

(2) Amounts for 2011 include throughput volumes of 199.4 and 13.3 bpd in thousands on terminals acquired from BP and ExxonMobil on June 1, 2011 and July 19, 2011, respectively.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Consolidated

Adjusted EBITDA. Adjusted EBITDA increased by $105.3 million, or 27.5%, to $487.9 million for the year ended December 31, 2011 from $382.6 million for the corresponding period in 2010. The International Operations, Pipelines & Terminals and Development & Logistics segments were responsible for the increase in Adjusted EBITDA. The International Operations segment increased Adjusted EBITDA by $117.7 million for the year ended December 31, 2011 as compared to the corresponding period in 2010 as a result of the acquisition of the BORCO facility in 2011 and a full year of operations for the Yabucoa terminal, which was acquired in December 2010. The Pipelines & Terminals segment's Adjusted EBITDA increased by $14.6 million for the year ended December 31, 2011 as compared to the corresponding period in 2010 as a result of a positive net contribution relating to pipeline and terminal acquisitions in 2011, higher pipeline tariff rates and terminalling contract rate escalations and an increase in other revenue, partially offset by a decrease in revenue due to lower pipeline and terminalling volumes on legacy assets, acquisition and integration expenses, higher cash operating expenses, unfavorable settlement experience and a decrease in earnings from equity investments primarily due to the sale of our interest in WT LPG. The Development & Logistics segment's Adjusted EBITDA increased by $2.7 million for the year ended December 31, 2011 as compared to the corresponding period in 2010, primarily due to expenses associated with a customer bankruptcy in the 2010 period, increased operating services contract margins as a result of new contracts and higher fees, a net contribution relating to the liquefied petroleum gas ("LPG") storage caverns acquired in November 2011 and increased project management margins, partially offset by higher operating and other costs and net proceeds from the ammonia linefill sale in the 2010 period.

These increases in Adjusted EBITDA were partially offset by a decrease in Adjusted EBITDA in the Natural Gas Storage and Energy Services segments. The Natural Gas Storage segment's Adjusted EBITDA decreased by $25.6 million for the year ended December 31, 2011 as compared to the corresponding period in 2010, resulting primarily due to a decrease in the hub services margin and net lease revenue due to decreased storage prices relating to low volatility in natural gas prices and compressed seasonal spreads in part due to system capacity constraints as a result of unplanned maintenance on a pipeline combined with excess supply and weak domestic demand and higher operating costs. The Energy Services segment's Adjusted EBITDA decreased by $4.1 million for the year ended December 31, 2011 as compared to the corresponding period in 2010 primarily due to declining basis which had an adverse effect on the net value of our inventory portfolio.

Revenue. Revenue was $4,759.6 million for the year ended December 31, 2011, which is an increase of $1,608.3 million, or 51.0%, from the year ended December 31, 2010. The increase in revenue for the year ended December 31, 2011 as compared to the corresponding period in 2010 was caused primarily by the following:

- an increase of $1,407.4 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, 2011 as compared to the corresponding period in 2010. The 198.7 million gallon increase in sales volume resulted in an increase in revenue of approximately $432.9 million and the increase in the average sales price per gallon from $2.18 in the 2010 period to $2.91 in the 2011 period, or approximately $0.73 per gallon, contributed to an increase in revenue of approximately $974.5 million;
- an increase of $193.1 million in revenue as a result of the BORCO acquisition in 2011 and a full year of revenue from the Yabucoa terminal, which was acquired in December 2010;
- an increase of $56.3 million in revenue from the Pipelines & Terminals segment as a result of pipeline and terminal acquisitions in 2011, higher pipeline tariff rates and terminalling contract rate escalations and an increase in other revenue, partially offset by a decrease due to lower pipeline and terminalling volumes on legacy assets and unfavorable settlement experience; and
- an increase of $5.4 million in revenue from the Development & Logistics segment primarily relates to an increase in operating services contract revenue as a result of new contracts and higher fees, an increase in project management and other revenue and a net contribution relating to the LPG storage caverns acquired in November 2011, partially offset by proceeds from the ammonia linefill sale in the 2010 period.

The increase in revenue was partially offset by:

- a decrease of $29.3 million in revenue from the Natural Gas Storage segment resulting primarily from a reduced level of hub services activities due to weakness in market fundamentals, including compressed seasonal spreads and lower lease revenue due to lower fees charged.

Total Costs and Expenses. Total costs and expenses were $4,570.7 million for the year ended December 31, 2011, which is an increase of $1,698.9 million, or 59.2%, from the corresponding period in 2010. Total costs and expenses reflect:

- an increase of $1,410.5 million in costs and expenses for the Energy Services segment primarily related to an increase of $1,413.2 in cost of product sales in the 2011 period as compared to the 2010 period, primarily as a result of increased refined petroleum product prices and increased volumes sold, an increase in property taxes, an increase in depreciation and amortization and an increase in other costs. The average cost of products sold increased from approximately $2.16 per gallon in the 2010 period to approximately $2.89 per gallon in the 2011 period, or approximately $0.73 per gallon, resulting in an increase in cost of products sold of approximately $984.4 million, and sales volumes increased by 198.7 million gallons between the 2010 and 2011 periods, contributing $428.8 million to the increase in cost of products sold. The increase in total costs and expenses was partially offset by a decrease in payroll costs, a decrease in bad debt expense and a decrease in compensation expense as a result of the equity plan modification expense during 2010;
- an increase of $163.9 million in costs and expenses for the Natural Gas Storage segment primarily related to a non-cash goodwill impairment charge, an increase in outside services and other costs due to well workover costs, an increase in depreciation and amortization and an increase in professional fees and other costs, partially offset by a decrease in cost of natural gas storage services, which includes hub services fees paid to customers for hub service activities, a decrease in compensation expense as a result of the equity plan modification expense during 2010 and a decrease in payroll costs;
- an increase of $116.3 million in costs and expenses for the International Operations segment as a result of the BORCO acquisition in 2011 and a full year of costs from the Yabucoa terminal, which was acquired in December 2010;
- an increase of $31.9 million in costs and expenses for the Pipelines & Terminals segment as a result of operating costs relating to pipeline and terminal acquisitions in 2011, an increase in depreciation and amortization, acquisition and integration expenses, an increase in environmental expenses, an increase in property taxes and an increase in payroll costs, partially offset by a decrease in compensation expense as a result of the modification of an equity compensation plan during 2010, a decrease in operating power costs, a decrease in professional fees, a decrease in outside services and a decrease in other expenses, primarily related to bad debt expense; and
- an increase of $0.8 million in costs and expenses for the Development & Logistics segment as a result of an increase in operating services contract costs as a result of new contracts, higher operating costs and other costs, an increase in project management activities and lower income tax benefit, partially offset by expenses associated with a customer bankruptcy in the 2010 period, a decrease in compensation expense as a result of the modification of an equity compensation plan during 2010 and a decrease in costs related to the retirement of certain assets.

Goodwill impairment expense, depreciation and amortization expense, equity plan modification expense and income tax benefit are not components of Adjusted EBITDA as presented in the reconciliation above.

Net income attributable to noncontrolling interests. Net income attributable to noncontrolling interests was $6.2 million for the year ended December 31, 2011 as compared to $157.9 million in the corresponding period in 2010. Noncontrolling interests primarily represents Services Company equity and portions of the Sabina Pipeline and WesPac Memphis that are not owned by Buckeye. The 2011 amount includes $1.7 million of noncontrolling interests expense related to the 20% of BORCO not acquired by us until February 16, 2011. For the 2010 period through November 19, 2010, the date of the Merger, noncontrolling interests also included equity interests in Buckeye that were not owned by BGH. These interests were eliminated in connection with the Merger.

Net income attributable to unitholders. Net income attributable to our unitholders was $108.5 million for the year ended December 31, 2011 compared to $43.1 million for the year ended December 31, 2010. Interest and debt expense increased by $30.4 million for the year ended December 31, 2011 as compared to the corresponding period in 2010, which increase was largely attributable to the issuance in January 2011 of the 4.875% Notes and higher outstanding borrowings under the BPL Credit Facility and the BES Credit Facility, partially offset by an increase of $5.1 million in capitalized interest, primarily as a result of the BORCO acquisition. Other revenue and expense items impacting operating income are discussed above.

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

Pipelines & Terminals

Adjusted EBITDA. Adjusted EBITDA from the Pipelines & Terminals segment of $361.0 million for the year ended December 31, 2011 increased by $14.6 million, or 4.2%, from $346.4 million for the corresponding period in 2010. The increase in Adjusted EBITDA was primarily due to a $22.8 million positive net contribution relating to pipeline and terminal acquisitions in 2011, $19.2 million due to higher pipeline tariff rates and terminalling contract rate escalations and a $9.0 million increase in other revenue.

These increases in Adjusted EBITDA were partially offset by a $12.5 million decrease in revenue due to lower pipeline and terminalling volumes on legacy assets, a $8.8 million increase in acquisition and integration expenses, a $7.5 million increase in operating expenses, $6.6 million in unfavorable settlement experience and a $1.0 million decrease in earnings from equity investments primarily due to the sale of our interest in WT LPG. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Pipelines & Terminals segment was $631.3 million for the year ended December 31, 2011, which is an increase of $56.3 million, or 9.8%, from the corresponding period in 2010. Revenues increased by $48.5 million due to pipeline and terminal acquisitions in 2011, $19.2 million due to higher pipeline tariff rates and terminalling contract rate escalations and a $9.0 million increase in other revenue.

These increases were partially offset by a $12.5 million decrease in revenue due to lower pipeline and terminalling volumes on legacy assets, $6.6 million in unfavorable settlement experience and a $1.3 million decrease due to operating services contract revenue attributable to contracts assigned to the Development & Logistics segment. Overall pipeline and terminalling volumes increased by 3.3% and 32.1%, respectively, as a result of the acquisition of pipeline and terminal assets in 2011. Excluding the impact of the acquisitions, pipeline volumes decreased by 1.3% primarily due to lower gasoline volumes as a result of lower demand caused by high commodity prices and supply interruptions due to severe weather conditions and lower heating oil volumes due to lack of contango in the market and refinery closures. Terminalling volumes decreased by 5.8% primarily due to lower ethanol volumes as a result of competitive pressures and lower gasoline and distillate volumes as a result of lower demand caused by high commodity prices and supply interruptions due to severe weather conditions and refinery maintenance issues.

Total Costs and Expenses. Total costs and expenses from the Pipelines & Terminals segment were $340.7 million for the year ended December 31, 2011, which is an increase of $31.9 million, or 10.3%, from the corresponding period in 2010. The increase in total costs and expenses was primarily due to $25.7 million of operating costs relating to pipeline and terminal acquisitions in 2011, a $9.2 million increase in depreciation and amortization as a result of newly acquired assets placed in service, a $8.8 million increase in acquisition and integration expenses, a $4.8 million increase in environmental expenses, a $3.0 million increase in property taxes and a $1.9 million increase in payroll costs.

These increases in total costs and expenses were partially offset by a $16.4 million decrease in compensation expense as a result of the equity plan modification during 2010 (see Note 18 in the Notes to the Consolidated Financial Statements), a $1.6 million decrease in operating power costs, a $1.3 million decrease in operating services contract costs attributable to contracts assigned to the Development & Logistics segment, a $0.7 million increase in professional fees, a $0.7 million increase in outside services and a $0.8 million decrease in other expenses, primarily relating to bad debt expense.

Depreciation and amortization expense and equity plan modification expense are not components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the Pipelines & Terminals segment was $290.6 million for the year ended December 31, 2011 compared to operating income of $266.2 million for the year ended December 31, 2010. Revenue and expense items impacting operating income are discussed above.

International Operations

Adjusted EBITDA. Adjusted EBITDA from the International Operations segment of $113.0 million for the year ended December 31, 2011 increased by $117.7 million from a loss of $4.7 million for the corresponding period in 2010. Adjusted EBITDA increased as the result of the BORCO acquisition in 2011 and a full year of operations for the Yabucoa terminal, which was acquired in December 2010. The increase in Adjusted EBITDA was primarily due to $185.5 million in revenue, partially offset by a $62.9 million in operating costs, a $3.2 million increase in acquisition and integration expenses and $1.7 million of noncontrolling interests expense related to the 20% of BORCO not acquired by us until February 16, 2011. The revenue and expense factors affecting Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the International Operations segment was $194.0 million for the year ended December 31, 2011, which is an increase of $193.1 million from the corresponding period in 2010. Revenue increased as a result of the BORCO acquisition in 2011 and a full year of revenue from the Yabucoa terminal, which was acquired in December 2010. The increase in revenue primarily related to a $151.0 million increase in storage fees, $18.1 million of berthing fees, which represent amounts charged to ships that utilize the facility's jetties, $16.4 million of other ancillary service revenue and $7.6 million related to the revenue recognition from unfavorable storage contracts acquired in connection with the BORCO acquisition, which is not a component of Adjusted EBITDA as presented in the reconciliation above.

Total Costs and Expenses. Total costs and expenses from the International Operations segment was $121.9 million for the year ended December 31, 2011, which is an increase of $116.3 million from the corresponding period in 2010. Total costs and expenses increased primarily due to costs related to operating the BORCO facility and a full year of costs for the Yabucoa terminal. The increase in total costs and expenses primarily related to $50.0 million in depreciation and amortization, $18.4 million in payroll costs, $15.1 million in repair, maintenance and other costs, $10.7 million in insurance costs, $8.1 million in lease expenses, $5.8 million in outside services, $5.0 million in fuel costs and a $3.2 million increase in acquisition and integration expenses. During December 31, 2010, total costs and expenses included $5.0 million in acquisition and integration costs relating to the BORCO facility and Yabucoa terminal. Depreciation and amortization is not a component of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the International Operations segment was $72.1 million for the year ended December 31, 2011. Revenue and expense items impacting operating income are discussed above.

Natural Gas Storage

Adjusted EBITDA. Adjusted EBITDA from the Natural Gas Storage segment of $4.2 million for the year ended December 31, 2011 decreased by $25.6 million, or 85.9%, from $29.8 million for the corresponding period in 2010. The decrease in Adjusted EBITDA was primarily the result of a $14.1 million and $8.6 million decrease in hub services margin and net lease revenue, respectively, due to decreased storage prices relating to low volatility in natural gas prices and compressed seasonal spreads in part due to system capacity constraints as a result of unplanned maintenance on a pipeline combined with excess supply and weak domestic demand and $2.9 million of higher operating costs during the year ended December 31, 2011. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Natural Gas Storage segment was $66.0 million for the year ended December 31, 2011, which is a decrease of $29.3 million, or 30.8%, from the corresponding period in 2010. Lease revenue and hub service fees are primarily determined by the difference in natural gas commodity prices for the periods in which natural gas is injected and withdrawn from the storage facility (i.e., time spread). Weakness in market fundamentals, including compressed seasonal spreads, resulted in a $20.7 million decrease in fees for hub service activities during the year ended December 31, 2011 as compared to the corresponding period in 2010. Lease revenue decreased $8.6 million for the year ended December 31, 2011, primarily due to a decrease in the fee charged for each volumetric unit of storage capacity leased.

Total Costs and Expenses. Total costs and expenses from the Natural Gas Storage segment were $243.2 million for the year ended December 31, 2011, which is an increase of $163.9 million, or 206.7%, from the corresponding period in 2010. The increase primarily relates to a $169.6 million non-cash goodwill impairment charge, a $2.6 million increase in outside services and other costs, primarily due to well workover costs, a $0.5 million increase in depreciation and amortization and a $0.4 million increase in professional fees and other costs, partially offset by a $6.7 million decrease in cost of natural gas storage services, which includes hub services fees paid to customers for hub service activities, a $1.9 million decrease in compensation expense as a result of the equity plan modification during 2010 and a $0.6 million decrease in payroll costs. Goodwill impairment expense, depreciation and amortization and equity plan modification expense are not components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income (Loss). Operating loss from the Natural Gas Storage segment was $177.2 million for the year ended December 31, 2011 compared to operating income of $16.1 million for the year ended December 31, 2010. Revenue and expense items impacting operating income are discussed above.

Energy Services

Adjusted EBITDA. Adjusted EBITDA from the Energy Services segment of $1.8 million for the year ended December 31, 2011 decreased by $4.1 million, or 69.3%, from $5.9 million for the corresponding period in 2010. The decrease in Adjusted EBITDA was primarily due to declining basis, which had an adverse effect on the net value of our inventory portfolio. During the period, market dynamics impacting the flow of product along the supply chain and warmer weather conditions, which resulted in decreased consumer demand created downward pressure on basis. At the rack, sales volumes were 17.4% higher than the 2010 period. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Energy Services segment was $3,889.0 million for the year ended December 31, 2011, which is an increase of $1,407.4 million, or 56.7%, from the corresponding period in 2010. This increase in revenue was primarily due to an increase in refined petroleum product average sales prices of approximately $0.73 per gallon (average sales price per gallon was $2.91 and $2.18 for the 2011 and 2010 periods, respectively) resulting in an increase of $974.5 million in the 2011 period, and an increase of 17.4% in sales volumes that contributed an additional $432.9 million in revenue.

Total Costs and Expenses. Total costs and expenses from the Energy Services segment were $3,893.4 million for the year ended December 31, 2011, which is an increase of $1,410.5 million, or 56.8%, from the corresponding period in 2010. The increase in total costs and expenses was primarily due to a $1,413.2 million increase in cost of product sales as a result of increased volumes sold and an increase in refined petroleum product prices (average cost of product sold per gallon was $2.89 and $2.16 for the 2011 and 2010 periods, respectively), a $0.7 million increase in property taxes, a $0.3 million increase in depreciation and amortization and a $0.3 million increase in other costs. The increase of $428.8 million and $984.4 million in the cost of product sold between the 2010 and 2011 periods, respectively, was due to the 17.4% increase in sales volumes and the $0.73 per gallon increase in product sales price.

These increases in total costs and expenses were partially offset by a $1.6 million decrease in payroll costs, a $1.3 million decrease in bad debt expense and a $1.1 million decrease in compensation expense as a result of the equity plan modification during 2010.

Depreciation and amortization and equity plan modification expense are not components of Adjusted EBITDA as presented in the reconciliation above.

Operating Income (Loss). Operating loss from the Energy Services segment was $4.5 million for the year ended December 31, 2011 compared to operating loss of $1.4 million for the year ended December 31, 2010. Revenue and expense items impacting operating income are discussed above.

Development & Logistics

Adjusted EBITDA. Adjusted EBITDA from the Development & Logistics segment of $7.9 million for the year ended December 31, 2011 increased by $2.7 million, or 52.7%, from $5.2 million for the corresponding period in 2010, primarily due to a $2.4 million in expenses associated with a customer bankruptcy in the 2010 period, a $1.5 million increase in operating services contract margins as a result of new contracts and higher fees, a $0.5 million net contribution relating to the LPG storage caverns acquired in November 2011 and a $0.3 million increase in project management margins, partially offset by $1.1 million of higher operating and other costs and $0.9 million of net proceeds from the ammonia linefill sale in the 2010 period. The revenue and expense factors affecting the variance in Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the Development & Logistics segment was $43.1 million for the year ended December 31, 2011, which is an increase of $5.4 million, or 14.3%, from the corresponding period in 2010. The increase in revenue was primarily due to a $4.5 million increase in operating services contract revenue as a result of new contracts and higher fees, a $1.3 million increase in project management and other revenue and $0.7 million net contribution relating to the LPG storage caverns acquired in November 2011, partially offset by the $1.1 million of proceeds from the ammonia linefill sale in the 2010 period.

Total Costs and Expenses. Total costs and expenses from the Development & Logistics segment were $35.2 million for the year ended December 31, 2011, which is an increase of $0.8 million, or 2.3%, from the corresponding period in 2010. The increase in total costs and expenses was primarily due to a $3.0 million increase in operating services contract costs as a result of new contracts, $1.1 million of higher operating and other costs, a $0.7 million increase in project management activities and $0.7 million of lower income tax benefit, partially offset by $2.4 million of expenses associated with a customer bankruptcy in the 2010 period, a $1.9 million decrease in compensation expense as a result of the equity plan modification during 2010 and a $0.4 million decrease in costs related to the retirement of certain assets. The income tax benefit and equity plan modification expense are not a component of Adjusted EBITDA as presented in the reconciliation above.

Operating Income. Operating income from the Development & Logistics segment was $7.9 million for the year ended December 31, 2011 compared to operating income of $3.3 million for the year ended December 31, 2010. Revenue and expense items impacting operating income are discussed above.

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 Pipelines & Terminals segment was primarily responsible for this increase in Adjusted EBITDA. The Pipelines & Terminals segment's Adjusted EBITDA increased by $44.2 million for the year ended December 31, 2010 as compared to the corresponding period in 2009, driven by the contribution from pipeline assets and terminals acquired in November 2009 and in the fourth quarter of 2010, the impact of internal growth projects, increased terminal throughput volumes, favorable settlement experience, higher terminal fees and tariff rates, increased storage, rental and other service revenues and lower operating expenses, partially offset by lower pipeline 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 and the impact of the negative Adjusted EBITDA from the International Operations 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. The International Operations segment's Adjusted EBITDA was a loss of $4.7 million for the year ended December 31, 2010, primarily due to professional fees related to the BORCO acquisition.

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. The 484 million gallon increase in sales volume resulted in an increase in revenue of approximately $831.2 million, and the increase in the average sales price per gallon from $1.72 in 2009 to $2.18 in 2010, or approximately $0.46 per gallon, contributed to an increase in revenue of approximately $525.4 million;
- an increase of $45.8 million in revenue from the Pipelines & Terminals segment, resulting from increased revenue from pipeline assets and terminals acquired in November 2009 and in the fourth quarter of 2010, increased terminal throughput volumes, higher terminal fees and tariff rates, 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, partially offset by the impact of slightly lower pipeline transportation volumes;
- 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 Pipelines & Terminals segment to the Development & Logistics segment in April 2010; and
- revenue of $0.9 million from the International Operations segment, as a result of the Yabucoa, Puerto Rico terminal acquisition in December 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. The average cost of product sold increased from approximately $1.66 per gallon in 2009 to approximately $2.16 per gallon in 2010, or approximately $0.50 per gallon, resulting in an increase in cost of product sold of approximately $568.6 million, and sales volumes increased 484 million gallons between 2009 and 2010, contributing $803.0 million to the increase in cost of product sold;
- 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;
- $5.6 million of costs and expenses of the International Operations segment, primarily due to professional fees related to the BORCO acquisition and costs for the terminal in Yabucoa, Puerto Rico, which was acquired in December 2010;
- 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 Pipelines & Terminals 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).

The increase in revenue was partially offset by:

- a decrease of $65.4 million in costs and expenses of the Pipelines & Terminals 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 pipeline 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 bad debt expense, property and other taxes, professional fees and project costs, integrity program expenses and operating expenses for pipeline and terminal assets acquired in November 2009 and in the fourth quarter of 2010.

Total costs and expenses in the 2009 period include the recognition of a non-cash $59.7 million asset impairment expense in the Pipelines & Terminals segment, related to the Buckeye NGL Pipeline and $32.1 million of expenses in the Pipelines & Terminals, Natural Gas Storage, Energy Services and Development & Logistics 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.

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.

Pipelines & Terminals

Adjusted EBITDA. Adjusted EBITDA from the Pipelines & Terminals segment of $346.4 million for the year ended December 31, 2010 increased by $44.2 million, or 14.7%, from $302.2 million for the corresponding period in 2009. The increase in Adjusted EBITDA was driven primarily by 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 terminal throughput volumes, favorable terminal settlement experience, higher fees and increased storage, rental and other service revenue, an $8.9 million benefit of higher tariff rates, favorable pipeline 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 pipeline 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 Pipelines & Terminals segment was $575.0 million for the year ended December 31, 2010, which is an increase of $45.8 million, or 8.6%, from the corresponding period in 2009. Revenues increased by $34.1 million 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, favorable settlement experience of $9.2 million, an increase of $8.9 million due to 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, 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 pipeline 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 due to the assignment of certain service contracts from the Pipelines & Terminals segment to the Development & Logistics segment in April 2010. Overall terminal 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 Pipelines & Terminals segment were $308.8 million for the year ended December 31, 2010, which is a decrease of $65.4 million, or 17.5%, 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 $28.9 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 17.5% 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 $16.4 million of compensation expense related to the modification of an equity compensation plan, a $5.0 million increase in professional fees, outside services and other project expenses, a $4.7 million increase in operating expenses for terminals acquired in November 2009 and in the fourth quarter of 2010, a $3.5 million increase in depreciation and amortization as a result of pipeline assets and terminals acquired in November 2009, a $3.3 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 $3.0 million increase in integrity program expenses and a $1.2 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 Pipelines & Terminals segment to the Development & Logistics segment, a $3.2 million decrease in payroll and benefits costs, resulting primarily from our best practices initiative, a $3.1 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 and a $0.6 million decrease in operating power costs due to lower pipeline transportation volumes and power contract renegotiations as part of our best practices initiative.

Operating Income. Operating income from the Pipelines & Terminals segment was $266.2 million for the year ended December 31, 2010 compared to operating income of $155.0 million for the year ended December 31, 2009. Revenue and expense items impacting operating income are discussed above.

International Operations

Adjusted EBITDA. Adjusted EBITDA from the International Operations segment was a loss of $4.7 million for the year ended December 31, 2010. The revenue and expense factors affecting Adjusted EBITDA are more fully discussed below.

Revenue. Revenue from the International Operations segment was $0.9 million for the year ended December 31, 2010. Revenue includes storage and terminalling fees from the terminal in Yabucoa, Puerto Rico from December 10, 2010, the date of acquisition, through December 31, 2010.

Total Costs and Expenses. Total costs and expenses from the International Operations segment were $5.6 million for the year ended December 31, 2010, and included $4.1 million of professional fees related to the BORCO acquisition. Total costs and expenses also include $1.5 million of costs related to the terminal in Yabucoa, Puerto Rico from the date of acquisition through December 31, 2010.

Operating Loss. Operating loss from the International Operations segment was $4.7 million for the year ended December 31, 2010. 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 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 average sales prices of approximately $0.46 per gallon (average sales price per gallon was $2.18 and $1.72 for 2010 and 2009, respectively) resulting in an increase of $525.4 million in the 2010 period, and an increase of 73.9% in sales volumes that contributed an additional $831.2 million in revenue.

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 (average cost of product sold per gallon was $2.16 and $1.66 for 2010 and 2009, respectively). The increase in the cost of product sold between 2009 and 2010 was due to the 73.9% increase in volume, and the $0.50 per gallon increase in product sales price was $803.0 million and $568.6 million, respectively. Total costs and expenses also increased for 2010 as compared to 2009 due to 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 Pipelines & Terminals 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.

General Outlook for 2012

In 2011, transportation volumes were impacted by weak consumer demand for gasoline, with rising gasoline prices and high unemployment representing key factors in that weakness, partially offset by higher year-over-year volumes for diesel and jet fuel. We expect that macro-economic demand for refined petroleum products in 2012 will be relatively flat compared to 2011, absent a significant upturn in the economy. As a result, we expect throughput volumes on our legacy pipeline systems will remain relatively flat as well and anticipate a modest increase in throughput volumes at our terminals. For both our pipeline and terminal assets, we expect marginal positive impact on volumes from recent growth capital projects on these legacy assets coming on-line. In addition, we expect to realize the benefit of increased tariffs on both our indexed and market-based pipeline systems, including the full year impact of 2011 tariff increases and further tariff increases in 2012. Ultimately, our ability to increase transportation and storage revenues is largely dependent on the strength of the overall economy in the markets we serve.

Our Pipelines & Terminals segment is expected to benefit in 2012 from a full year of contribution from our 2011 acquisitions, including the assets acquired from BP and ExxonMobil in June 2011 and July 2011, respectively. In addition, we expect to benefit from the contribution from the Perth Amboy Facility acquisition, which we expect to close late in the second quarter of 2012.

Our International Operations segment results in 2011 were adversely impacted by lower than expected berthing revenue due to reductions in availability of fuel oil blending components due primarily to operational issues at a refinery in the U.S. Virgin Islands ("Caribbean refinery") and lower vessel traffic as inventory optimization opportunities were limited given market conditions. These market conditions also created some weakness in demand for product storage in 2011. Looking forward to 2012 and beyond, we are seeing increased customer interest for both crude and refined product storage. Near term crude demand has increased following the announcement of the shutdown of the Caribbean refinery and longer term demand is being driven by the ramp up of crude production in South America. We believe the closure of the Caribbean refinery and the continued rationalization of Northeast refineries position BORCO to capitalize on increased demand for refined product storage as customers re-work their logistics chains to respond to changing supply patterns. We may experience some softness in demand for berthing and other ancillary services if the forward product pricing does not create inventory optimization opportunities for our customers, although we do not expect the lack of availability of blending components to impact 2012 as our customer has secured an alternate source of supply. BORCO is also expected to benefit in 2012 as the first phase of our expansion project begins to come on-line in the second half of the year.

Our Natural Gas Storage segment was adversely impacted in 2011 by continued weakness in the market as both firm lease rates and seasonal spreads fell to severely depressed levels. We expect market conditions to remain challenging in 2012.

Our Energy Services segment performed in line with expectations for the first three quarters of 2011, but the fourth quarter results were negatively impacted by event driven basis moves in the Northeast and basis weakness in the Midwest. In addition, the lack of contango in the market and a warmer than normal winter, particularly in the Northeast, further depressed fourth quarter results. Looking forward to 2012, we expect Energy Services performance to improve over 2011 results as the segment adjusts its strategy to reduce basis pricing risk prospectively by, among other initiatives, reducing the amount of inventory carried and refocusing its marketing effort on fewer, more strategic locations. While this strategy will not eliminate basis risk, it will reduce our potential exposure. We believe the Energy Services segment will continue to be a key driver in utilization of pipeline and terminal assets.

For our Development & Logistics segment, operations have expanded due to various business endeavors, including operating our new South Portland, Maine terminal and our newly acquired LPG storage caverns. We anticipate our Development & Logistics segment to continue to achieve modest growth as they identify new business opportunities.

During 2011, we successfully accessed both the debt and equity markets in order to provide funding for our recent acquisitions and growth capital expenditures. In the first quarter of 2012, we accessed the equity market in order to secure funding in advance of the closing of the Perth Amboy Facility acquisition as well as to fund certain anticipated growth capital projects during 2012. Although we believe we will not require additional equity funding in 2012 absent unforeseen circumstances, we believe that, under current market conditions, we could raise additional capital in both the debt and equity markets on acceptable terms.

Throughout 2012, we will continue to evaluate opportunities to acquire or construct assets that are complementary to our businesses and support our long-term growth strategy and will determine the appropriate financing structure for any opportunity we pursue.

The forward-looking statements contained in this "General Outlook for 2012" speak only as of the date hereof. Although the expectations in the forward-looking statements are based on our current beliefs and expectations, caution should be taken not to place undue reliance on any such forward-looking statements because such statements speak only as of the date hereof. Except as required by federal and state securities laws, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or any other reason. All such forward-looking statements are expressly qualified in their entirety by the cautionary statements contained or referred to in this Report, including under the captions "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements" and elsewhere in this Report and in our future periodic reports filed with the SEC. In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this "General Outlook for 2012" may not occur.

Liquidity and Capital Resources

General

The following section describes our liquidity and capital requirements, including sources and uses of liquidity and capital resources. Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to partners. Our principal sources of liquidity are cash from operations, borrowings under our Credit Facility and proceeds from the issuance of our units. We will, from time to time, issue debt securities to permanently finance amounts borrowed under our Credit Facility. Buckeye Energy Services LLC ("BES") funds its working capital needs principally from its operations and its portion of the Credit Facility. Our financial policy has been to fund sustaining capital expenditures with cash from operations. Expansion and cost improvement capital expenditures, along with acquisitions, have typically been funded from external sources including our BPL Credit 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.

During February 2012, we issued 4,262,575 LP Units to institutional investors in a registered direct offering for aggregate consideration of approximately $250.0 million.

During 2011, we issued equity and debt, which financed acquisitions and expansion projects. During January and February 2011, we completed the purchase of First Reserve's and Vopak's interests in FRBCH for approximately $1.4 billion in cash and equity and repaid BORCO's outstanding indebtedness and settled their interest rate derivative instruments, collectively representing approximately $318.2 million. To fund a portion of the acquisition, we issued $650.0 million of our 4.875% Notes due 2021 and issued 5,794,725 LP Units and 1,314,870 Class B Units to institutional investors for aggregate consideration of approximately $425.0 million. Also, we issued 2,483,444 LP Units and 4,382,889 Class B Units to First Reserve as $400.0 million of consideration and 620,861 LP Units and 1,095,722 Class B Units to Vopak as $100.0 million of consideration. In April 2011, we issued 5,520,000 LP Units in an underwritten public offering with net proceeds of $316.6 million. In May 2011, we sold our 20% interest in WT LPG for $85.0 million. Then, in June 2011, we acquired pipeline and terminal assets from BP for $166.0 million, and in July 2011, we acquired a terminal in Bangor, Maine, a terminal in Portland, Maine through a 50/50 joint venture with Irving and a 124-mile pipeline that connects the two terminals from ExxonMobil for $23.5 million. In September 2011, Buckeye and BES entered into a Credit Facility with SunTrust Bank and other lenders to provide for a $1.25 billion senior unsecured revolving credit agreement.

As a result of our financing activities in 2012 and 2011 and in light of the fact that none of our long-term debt obligations mature prior to 2013, we believe that borrowing capacity under our Credit Facility, ongoing cash flows from operations and the registered direct offering in February 2012 will be sufficient to fund our operations for the remainder of 2012, including our expansion plans. We will continue to evaluate a variety of financing sources, including the debt and equity markets described above throughout 2012.

Current Liquidity

As of December 31, 2011, we had the following liquidity available to meet our working capital needs, capital expenditures, business acquisitions and distributions to partners as of the period indicated (in thousands):

	December 31, 2011
Cash and cash equivalents	$ 12,986
Availability under the Credit Facility	492,943
Total available liquidity	$ 505,929

At December 31, 2011, we had total fixed-rate debt obligations at face value of $2,075.0 million, consisting of $300.0 million of the 4.625% Notes, $275.0 million of the 5.300% Notes, $125.0 million of the 5.125% Notes, $300.0 million of the 6.050% Notes, $275.0 million of the 5.500% Notes, $650.0 million of the 4.875% Notes and $150.0 million of the 6.750% Notes and our variable-rate obligations were $575.2 million under the Credit Facility. See Note 12 in the Notes to Consolidated Financial Statements for more information about the terms of our debt.

The fair values of our aggregate debt and credit facilities were estimated to be $2,811.7 million and $1,897.5 million at December 31, 2011 and 2010, respectively.

Notes Offering

On January 13, 2011, we sold the 4.875% Notes in an underwritten public offering. The notes were issued at 99.62% of their principal amount. Total proceeds from this offering, after underwriters' fees, expenses and debt issuance costs of $4.9 million, were approximately $642.6 million, and were used to fund a portion of the purchase price for our acquisition of BORCO. See Note 3 in the Notes to Consolidated Financial Statements for further discussion of the BORCO acquisition.

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

Credit Facility

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

Equity

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

On April 15, 2011, we issued 5,520,000 LP Units, which included 720,000 LP Units issued as part of the overallotment option, in an underwritten public offering at a public offering price of $59.41 per LP Unit. Total proceeds from the offering, including the overallotment option and after the underwriters' discount of $1.99 per LP Unit and offering expenses, were approximately $316.6 million, and were used to reduce amounts outstanding under our Prior BPL Credit Facility.

On February 13, 2012, we issued 4,262,575 LP units to institutional investors in a registered direct offering for aggregate consideration of approximately $250.0 million at a price of $58.65 per LP Unit, before deducting placement agents fees and estimated offering expenses. We plan to use the net proceeds from this offering to fund indirectly a portion of the Perth Amboy Facility and certain other growth capital expenditures, and, pending such uses, to reduce the indebtedness outstanding under our Credit Facility.

Capital Structuring Transactions

As part of our ongoing efforts to maintain a capital structure that is closely aligned with the cash-generating potential of our asset-based business, we may explore additional sources of external liquidity, including public or private debt or equity issuances. Matters to be considered will include cash interest expense and maturity profile, all to be balanced with maintaining adequate liquidity. We have a universal shelf registration statement that does not place any dollar limits on the amount of debt and equity securities that we may issue thereunder and a traditional shelf registration statement that currently has a $750.0 million limit on the amount of equity securities that we may issue thereunder on file with the SEC. The timing of any transaction may be impacted by events, such as strategic growth opportunities, legal judgments or regulatory or environmental requirements. The receptiveness of the capital markets to an offering of debt or equity securities cannot be assured and may be negatively impacted by, among other things, our long-term business prospects and other factors beyond our control, including market conditions.

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,		
	2011	2010	2009
Cash provided by (used in):			
Operating activities	$ 403,892	$ 292,479	$ 47,662
Investing activities	(1,310,279)	(114,188)	(144,203)
Financing activities	905,747	(202,239)	72,834

Operating Activities

2011 Compared to 2010. Net cash flows provided by operating activities was $403.9 million for the year ended December 31, 2011 compared to $292.5 million for the year ended December 31, 2010. The increase in cash provided by operating activities primarily relates to cash generated from our recent acquisitions of the BORCO facility, Yabucoa terminal and several pipelines and terminals acquisitions, including the assets acquired from BP, and a $102.5 million cash inflow related to a decrease in inventory, partially offset by a $19.2 million increase in interest and debt expense during 2011.

2010 Compared to 2009. Net cash flows 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 increase in cash provided by operating activities primarily relates to a $10.0 million cash inflow related to a decrease in inventory during 2010 as compared to 2009 cash outflow related to an increase in inventory as a result of energy market conditions and cash generated from terminals acquired in November 2009, partially offset by a $16.7 million increase in interest and debt expense during 2010.

Future Operating Cash Flows. Our future operating cash flows will vary based on a number of factors, many of which are beyond our control, including the cost of commodities, the effectiveness of our strategy, legal environmental and regulatory requirements and our ability to capture value associated with commodity price volatility.

Investing Activities

2011 Compared to 2010. Net cash flows used in investing activities was $1,310.3 million for the year ended December 31, 2011 compared to $114.2 million for the year ended December 31, 2010. The increase in cash used in investing activities primarily relates to our recent acquisitions of the pipeline and terminal assets from BP and a pipeline, terminal and equity investment from ExxonMobil for approximately $166.0 million and $23.5 million, respectively. Additionally, we acquired BORCO by purchasing interests from First Reserve and Vopak on January 18, 2011 and February 16, 2011, respectively, for approximately $1.4 billion of total consideration, consisting of $893.7 million in cash, which is net of cash acquired of $27.0 million. The remaining consideration of $503.5 million consisted of the issuance of LP Units and Class B Units. See Note 26 in the Notes to Consolidated Financial Statements. Additionally, we had a $227.6 million increase in capital expenditures for the year ended December 31, 2011 compared with the year ended December 31, 2010. See below for a discussion of capital spending. The increase in investing activities was partially offset by cash proceeds received from the sale of our 20% interest in WT LTP of $85.0 million during the year ended December 31, 2011 as compared to cash proceeds from the sale of the Buckeye NGL Pipeline of $22.0 million during the year ended December 31, 2010.

For further discussion on our acquisitions, see Note 3 in the Notes to Consolidated Financial Statements.

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 decrease in cash used in investing activities primarily relates to the cash proceeds from the sale of the Buckeye NGL Pipeline of $22.0 million during the year ended December 31, 2010.

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,		
	2011	2010	2009
Sustaining capital expenditures	$ 57,467	$ 31,244	$ 23,496
Expansion and cost reduction	247,857	46,455	63,813
Total capital expenditures, net	$ 305,324	$ 77,699	$ 87,309

In 2011, expansion and cost reduction projects included initiation of a significant storage tank expansion project as well as upgrades and expansion of a jetty structure and inland dock at BORCO, terminal ethanol and butane blending, new pipeline connections, new natural gas storage wells, continued progress on a new pipeline and terminal billing system as well as various other operating infrastructure projects. In 2010 and 2009, 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, 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.

We expect to spend approximately $250.0 million to $330.0 million for capital expenditures in 2012, of which approximately $50.0 million to $70.0 million is expected to relate to sustaining capital expenditures and $200.0 million to $260.0 million is expected to relate to expansion and cost reduction projects. Approximately $130.0 million to $180.0 million of these amounts are related to capital expenditures in 2012 for the BORCO facility, of which $120.0 million to $160.0 million is expected to relate to expansion projects and $10.0 million to $20.0 million is expected to relate to sustaining capital expenditures. Approximately $120.0 million to $150.0 million of these amounts are related to capital expenditures in 2012 for our other assets, excluding the BORCO facility, of which $80.0 million to $100.0 million is expected to relate to expansion projects and $40.0 million to $50.0 million is expected to relate to sustaining capital expenditures. 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 2012 will include storage tank expansion projects at the BORCO facility, completion of additional storage tanks and rail loading facilities in the Midwest, the refurbishment of storage tanks and facilities in the Northeast, continued installation of vapor recovery units throughout our system of terminals, additive system installation throughout our terminal infrastructure and various upgrades and expansions of our ethanol business. Cost reduction expenditures improve operational efficiencies or reduce costs.

Financing Activities

2011 Compared to 2010. Net cash flows provided by financing activities was $905.7 million for the year ended December 31, 2011 compared to net cash flow used in financing activities of $202.2 million for the year ended December 31, 2010. The increase in cash provided by financing activities primarily related to borrowings under the BPL Credit Facility, net proceeds from issuance of units and issuance of long-term debt. We borrowed of $1,221.7 million and $298.4 million under the BPL Credit Facility during the years ended December 31, 2011 and 2010, respectively. In January 2011, we received total proceeds of $425.0 million from the issuance of 5,794,725 LP Units and 1,314,870 Class B Units to institutional investors, before deducting equity issuance of approximately $4.6 million to fund a portion of the BORCO acquisition. We received $316.6 million in net proceeds from an underwritten equity offering in April 2011 for the public issuance of 5,520,000 LP Units. Also, we received $647.5 million from the issuance in January 2011 of $650.0 million in aggregate principal amount of the 4.875% Notes in an underwritten public offering.

These increases in cash provided by financing activities were offset by repayment under the BPL Credit Facility, repayment of debt assumed and cash distributions. We repaid $995.7 million and $278.4 million under the BPL Credit Facility during the years ended December 31, 2011 and 2010, respectively. Also, we repaid $318.2 million of debt assumed in the BORCO acquisition, which includes settlement of BORCO's interest rate derivative instruments. See Note 3 in the Notes to Consolidated Financial Statements. Cash distributions paid to our partners were $335.7 million ($4.025 per LP Unit) for the year ended December 31, 2011. Cash distributions paid to partners of BGH were $49.8 million ($1.76 per unit) during the year ended 2010. In connection with the Merger, BGH's units were converted into Buckeye LP Units. Additionally, distributions to noncontrolling partners of Buckeye, consisting primarily of distributions paid by the Sabina Pipeline and WesPac Memphis, were $8.9 million during the year ended December 31, 2011. Distributions to noncontrolling partners of Buckeye, consisting primarily of distributions to holders of LP Units, were $195.6 million during the year ended 2010. Buckeye paid cash distributions of $3.825 per LP Unit in the 2010 period. In connection with the Merger, the majority of noncontrolling interests were eliminated.

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 increase in cash used in financing activities primarily relates to net proceeds received of $104.6 million from an underwritten equity offering in March and April of 2009 for the public issuance of 3.0 million LP Units. Also, 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. Additionally, increase in cash was due to net borrowings under the BES Credit Agreement of $44.5 million and $143.8 million during the years ended December 31, 2010 and 2009, respectively. 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.

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:

Business Combinations

We allocate the total purchase price of a business combination to the assets acquired and the liabilities assumed based on their estimated fair values at the acquisition date, with the excess purchase price recorded as goodwill. For all material acquisitions, we engage an independent valuation specialist to assist us in determining the fair value of the assets acquired and liabilities assumed, including goodwill, based on recognized business valuation methodology. If the initial accounting for the business combination is incomplete by the end of the reporting period in which the acquisition occurs, an estimate will be recorded. Subsequent to the acquisition but not to exceed one year from the acquisition date, we will record any material adjustments retrospectively to the initial estimate based on new information obtained about facts and circumstances that existed as of the acquisition date. Also, we expense any acquisition-related costs as incurred in connection with each business combination. An income, market or cost valuation method may be utilized to estimate the fair value of the assets acquired or liabilities assumed in a business combination. The income valuation method represents the present value of future cash flows over the life of the asset using (i) discrete financial forecasts, which rely on management's estimates of revenue, operating expenses and volumes, (ii) long-term growth rates and (iii) appropriate discount rates. The market valuation method uses prices paid for a reasonably similar asset by other purchasers in the market, with adjustments relating to any differences between the assets. The cost valuation method is based on the replacement cost of a comparable asset at prices at the time of the acquisition reduced for depreciation of the asset.

Measuring the Fair Value of 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.

We may perform a qualitative assessment to determine whether the fair value of our reporting units are more likely than not less than the carrying amount. If we believe the fair value is less than the carrying amount, we will perform step one of the two-step goodwill impairment test. See "*Recent Accounting Developments*" in Note 2 in the Notes to the Consolidated Financial Statements for discussion of the amended guidance. The first step of the goodwill impairment test determines whether an impairment exists by comparing the fair value of a reporting unit with its carrying amount, including goodwill. If the estimated fair value of the reporting unit exceeds its carrying amount, no impairment is necessary. If the carrying amount of a reporting unit exceeds its estimated fair value, the second step measures the amount of impairment by comparing the implied fair value of the reporting unit goodwill with the carrying amount of that goodwill. We would assign the fair value of a reporting unit to all of the assets and liabilities of that unit as if the reporting unit had been acquired in a business combination. The excess of the fair value of a reporting unit over the amounts assigned to its assets and liabilities is the implied fair value of goodwill. The estimate of the fair value of the reporting unit is determined using a combination of an expected present value of future cash flows and a market multiple valuation method. The present value of future cash flows is estimated using (i) discrete financial forecasts, which rely on management's estimates of revenue, operating expenses and volumes, (ii) long-term growth rates and (iii) appropriate discount rates. The market multiple valuation method uses appropriate market multiples from comparable companies on the reporting unit's earnings before interest, tax, depreciation and amortization. We evaluate industry and market conditions for purposes of weighting the income and market valuation approach.

In the third quarter of 2011, we recorded a non-cash goodwill impairment charge of $169.6 million in the Natural Gas Storage segment. For the reporting units with goodwill as of January 1, 2012, each reporting unit's fair value was in excess of its carrying value. We did not record any goodwill impairment charges during the years ended December 31, 2010 and 2009. See Note 9 in the Notes to Consolidated Financial Statements for additional information regarding our goodwill.

Measuring Recoverability of Long-Lived Assets and Equity Method Investments

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 determine the estimated undiscounted future cash flows expected to result from the use of the asset and its eventual disposal. If the sum of the estimated undiscounted future cash flows exceeds the carrying amount, no impairment is necessary. If the carrying amount exceeds the sum of the undiscounted cash flows, an impairment charge is recognized based on 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. Estimates of future undiscounted net cash flows include discrete financial forecasts, which rely on management's estimates of revenue, 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.

In the third quarter of 2011, we considered the goodwill impairment in the Natural Gas Storage segment an indicator of impairment related to the long-lived assets associated with the Natural Gas Storage reporting unit. Accordingly, we evaluated these assets for impairment and concluded that no impairment of the long-lived asset existed. During the year ended December 31, 2009, we recorded an impairment of $59.7 million related to an impairment of Buckeye NGL. See Note 7 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 recording an impairment charge.

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, 2011, 2010 and 2009, we incurred environmental expenses, net of insurance recoveries, of $14.0 million, $8.5 million and $10.6 million, respectively. At December 31, 2011 and 2010, we had accrued $58.4 million and $30.8 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 15 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, 2011, we had approximately $4.3 million of net assets for physical derivative contracts in our consolidated financial statements. At December 31, 2011, the net fair value of the non-designated futures contracts is approximately $0.4 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 $0.2 million at December 31, 2011 and has been recognized as assets 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 fixed-price and index 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 and index derivative contracts for the procurement of future inventory. In addition, we enter into physical fixed-price sales contracts for customers electing to fix the price of their refined petroleum product needs. The fixed-price and index 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 sales contracts are privately negotiated with customers of the Energy Services segment who are generally smaller, private companies that may not have established credit ratings, the determination of an adjustment to fair value to reflect counterparty credit risk (a "credit valuation adjustment") requires significant management judgment. At December 31, 2011, we had reduced the fair value of the fixed-price contracts by a $0.1 million credit valuation adjustment to reflect this counterparty credit risk. The delivery periods for the contracts range from one to twelve months, with the substantial majority of deliveries concentrated in the first four months of 2012.

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.

Additionally, 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 by mitigating the adverse effect of a change in the capital market. We have elected cash flow hedge accounting for these interest rate swaps as we expect the change in fair value of the swap instruments to be highly effective at offsetting the cash flow associated with the forecasted interest payments from the underlying debt. The effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income and reclassified to earnings in the same period or periods during which the hedged transactions affects earnings. The portion of the change in fair value of the hedge instrument that is ineffective and the hedge components excluded from the assessment of effectiveness are recognized in current earnings. The fair value of the swap instruments are calculated by discounting the future cash flows of both the fixed rate and variable rate interest payments using appropriate discount rates with consideration given to our non-performance risk. We have determined that the inputs used in measuring the fair value of these swap instruments fall within Level 2 of the fair value hierarchy.

Other Considerations

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2011 (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)	$ 2,399,000	$ —	$ 575,000	$ 324,000	$ 1,500,000
Interest payments (2)	854,891	115,410	207,445	172,482	359,554
Operating leases: (3)					
Office space and other	27,606	2,443	5,279	5,637	14,247
Equipment (4)	9,188	3,487	5,701	—	—
Land leases (5)	414,457	5,672	11,681	12,155	384,949
Purchase obligations (6)	145,567	145,567	—	—	—
Capital expenditure obligations (7)	16,328	16,328	—	—	—
Total contractual obligations	$ 3,867,037	$ 288,907	$ 805,106	$ 514,274	$ 2,258,750

(1) We have long-term payment obligations under our Credit Facility and our underwritten publicly issued notes. As of December 31, 2011, the amount borrowed by Buckeye under our Credit Facility will not be repaid until the maturity date of the facility; the amount borrowed by BES under the Credit Facility is classified as a current liability as related funds are used to finance their current working capital needs. See Note 12 in the Notes to Consolidated Financial Statements for additional information regarding our debt obligations.

(2) 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.

(3) We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Amounts shown in the table represent minimum lease payment obligations under our operating leases with terms in excess of one year for the periods indicated. Lease expense is charged to operating expenses on a straight line basis over the period of expected benefit. Contingent rental payments are expensed as incurred and not included in the table above. Total rental expense for the years ended December 31, 2011, 2010 and 2009 was $30.1 million, $21.3 million and $21.2 million, respectively.

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

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

(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, 2011.

(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.

Our rights-of-way payments were approximately $6.6 million for the year ended December 31, 2011 and are subject to an annual escalation for the remaining life of all pipelines and terminals.

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

In connection with the March 2011 repayment of the ESOP Notes, the ESOP was frozen with respect to participation and benefits effective March 27, 2011 (the "Freeze Date"). No Company contributions (other than dividend equivalent payments) will be made on behalf of current participants in the Plan on and after the Freeze Date. Even though contributions under the ESOP are no longer being made, each eligible participant's ESOP Account will continue to be credited with its share of any stock dividends or other stock distributions associated with Services Company Stock.

Services Company stock was 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. All Services Company stock has been released to ESOP participants. 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 12 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. BORCO's functional currency is the U.S. dollar and it is equivalent in value with the Bahamian dollar. Foreign exchange gains and losses arising from transactions denominated in a currency other than the functional currency relate to a nominal amount of supply purchases and are included in net income (loss) in the consolidated statements of operations. The effects of foreign currency transactions were not considered to be material for the year ended December 31, 2011 and 2010.

Commodity Price Risk

Natural Gas Storage

Our 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 facilities, 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, it is subject to commodity price 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, 2011, the Natural Gas Storage segment has recorded the following assets and liabilities related to its hub services agreements (in thousands):

	December 31, 2011
Assets:	
Hub service agreement	$ 18,301
Liabilities:	
Hub service agreements	(6,911)
Total	$ 11,390

Energy Services

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

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

As of December 31, 2011, the Energy Services segment had derivative assets and liabilities as follows (in thousands):

	December 31, 2011
Assets:	
Physical fixed price derivative contracts	$ 5,292
Physical index derivative contracts	834
Futures contracts for refined products	630
Liabilities:	
Physical fixed price derivative contracts	(1,245)
Physical index derivative contracts	(614)
Total	$ 4,897

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

		Year Ended December 31,	
	Location	2011	2010
Fair value hedge ineffectiveness (excluding time value)	Cost of product sales and natural gas storage services	$ (500)	$ 9,746
Time value excluded from hedge assessment	Cost of product sales and natural gas storage services	(9,195)	(15,576)
Net loss in income		$ (9,695)	$ (5,830)

Our hedged inventory portfolio extended to the second quarter of 2012. The majority of the unrealized loss at December 31, 2011 for inventory hedges represented by futures contracts will be realized by the second quarter of 2012 as the related inventory is sold. At December 31, 2011, open refined petroleum product derivative contracts varied in duration in the overall portfolio, but did not extend beyond December 2012. In addition, at December 31, 2011, we had refined petroleum product inventories that we intend to use to satisfy a portion of the physical fixed price derivative contracts.

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

Based on a hypothetical 10% movement in the underlying quoted market prices of the futures contracts, physical fixed price and index derivative contracts, and designated hedged refined petroleum products inventories outstanding at December 31, 2011, the estimated fair value of the portfolio of commodity financial instruments and designated hedged refined petroleum products inventories would be as follows (in thousands):

Scenario	Resulting Classification	Commodity Financial Instrument Portfolio Fair Value
Fair value assuming no change in underlying commodity prices (as is)	Asset	$ 279,049
Fair value assuming 10% increase in underlying commodity prices	Asset	$ 280,314
Fair value assuming 10% decrease in underlying commodity prices	Asset	$ 277,784

The value of the open futures contract positions noted above were based upon quoted market prices obtained from NYMEX. The value of the physical derivative contracts and physical inventories designated in a fair value hedge relationship was based on observable market data from third party pricing publications.

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 by mitigating the adverse effect of a change in the capital market. 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 change in fair value of the swap instruments is positive and the counterparty may 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 aligning the swap instrument with the existing underlying debt obligation or a specified expected debt issuance generally associated with the maturity of an existing debt obligation.

Our practice with respect to derivative transactions related to interest rate risk has been to have each transaction in connection with non-routine borrowings authorized by the Board of Directors of Buckeye GP. In February 2009, Buckeye GP's Board of Directors adopted an interest rate hedging policy which permits us to enter into certain short-term interest rate hedge agreements to manage our interest rate and cash flow risks associated with our 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, 2011, we had total fixed-rate debt obligations at face value of $2,075.0 million, consisting of $300.0 million of the 4.625% Notes, $275.0 million of the 5.300% Notes, $125.0 million of the 5.125% Notes, $300.0 million of the 6.050% Notes, $275.0 million of the 5.500% Notes, $650.0 million of the 4.875% Notes and $150.0 million of the 6.750% Notes. The fair value of these fixed-rate debt obligations at December 31, 2011 was approximately $2,236.6 million. We estimate that a 1% increase or decrease in rates for obligations of similar maturities would decrease or increase the fair value of our fixed-rate debt obligations at December 31, 2011 by approximately $130.0 million or $118.8 million, respectively.

At December 31, 2011, our variable-rate obligations were $575.2 million under the Credit Facility. Based on the balance outstanding at December 31, 2011, we estimate that a 1% increase or decrease in interest rates would increase or decrease annual interest expense by approximately $5.8 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. We have entered into six forward-starting interest rate swaps with a total aggregate notional amount of $300.0 million related to the anticipated issuance of debt on or before July 15, 2013 and six forward-starting interest rate swaps with a total aggregate notional amount of $275.0 million related to the anticipated issuance of debt on or before October 15, 2014. The purpose of these swaps is to hedge the variability of the forecasted interest payments on these expected debt issuances that may result from changes in the benchmark interest rate until the expected debt is issued. During the year ended December 31, 2011, unrealized losses of $104.8 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.

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, 2011 (in thousands):

Scenario	Resulting Classification	Financial Instrument Portfolio Fair Value
Fair value assuming no change in underlying interest rates (as is)....	Liability	$ (101,911)
Fair value assuming 10% increase in underlying interest rates......	Liability	$ (90,175)
Fair value assuming 10% decrease in underlying interest rates......	Liability	$ (119,275)

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Buckeye GP LLC, 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 ("GAAP") 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.

In conducting our evaluation of the effectiveness of our internal control over financial reporting, we excluded the internal control over financial reporting of Bahamas Oil Refining Company International Limited ("BORCO"), which was consolidated into our financial statements on January 18, 2011, due to its size, conversion to GAAP, implementation of our internal control structure and certain system implementations. BORCO constituted approximately 35.6% of total assets, 3.7% of total revenue and 21.9% of Adjusted EBITDA (as defined in Note 25 in the Notes to Consolidated Financial Statements) of the consolidated financial statement amounts as of and for the year ended December 31, 2011. Such exclusion was in accordance with Securities and Exchange Commission guidance that an assessment of a recently acquired business may be omitted in management's report on internal controls over financial reporting, providing the acquisition took place within twelve months of management's evaluation.

Management evaluated the internal control over financial reporting of Buckeye as of December 31, 2011. 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, 2011, the internal control over financial reporting of Buckeye was effective.

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

/s/ CLARK C. SMITH	/s/ KEITH E. ST.CLAIR
Clark C. Smith Chief Executive Officer, President and Director	Keith E. St.Clair Executive Vice President and Chief Financial Officer

February 27, 2012

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, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management's Report on Internal Control Over Financial Reporting, management excluded from its assessment the internal control over financial reporting of Bahamas Oil Refining Company International Limited ("BORCO"), which was consolidated into Buckeye's financial statements on January 18, 2011, and whose financial statements constitute approximately 35.6% of total assets, 3.7% of total revenue and 21.9% of Adjusted EBITDA (as defined in Note 25 in the Notes to Consolidated Financial Statements) of the consolidated financial statement amounts as of and for the year ended December 31, 2011. Accordingly, our audit did not include the internal control over financial reporting at BORCO. 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, 2011, 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, 2011 of Buckeye and our report dated February 27, 2012 expressed an unqualified opinion on those consolidated financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 27, 2012

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, 2011 and 2010, 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, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, 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 27, 2012 expressed an unqualified opinion on Buckeye's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 27, 2012

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

	Year Ended December 31,		
	2011	2010	2009
Revenue:			
Product sales	$ 3,844,888	$ 2,469,210	$ 1,125,653
Transportation and other services	914,722	682,058	644,719
Total revenue	4,759,610	3,151,268	1,770,372
Costs and expenses:			
Cost of product sales and natural gas storage services	3,851,579	2,462,275	1,103,015
Operating expenses	365,941	278,245	275,930
Depreciation and amortization	119,534	59,590	54,699
Asset impairment expense	—	—	59,724
Goodwill impairment expense	169,560	—	—
General and administrative	64,122	50,599	41,147
Equity plan modification expense	—	21,058	—
Reorganization expense	—	—	32,057
Total costs and expenses	4,570,736	2,871,767	1,566,572
Operating income	188,874	279,501	203,800
Other income (expense):			
Earnings from equity investments	10,434	11,363	12,531
Gain on sale of equity investment	34,727	—	—
Interest and debt expense	(119,561)	(89,169)	(75,147)
Other income (expense), net	190	(687)	453
Total other expense	(74,210)	(78,493)	(62,163)
Net income	114,664	201,008	141,637
Less: net income attributable to noncontrolling interests	(6,163)	(157,928)	(92,043)
Net income attributable to Buckeye Partners, L.P.	$ 108,501	$ 43,080	$ 49,594
Earnings per unit:			
Basic	$ 1.20	$ 1.66	$ 2.49
Diluted	$ 1.20	$ 1.65	$ 2.49
Weighted average units outstanding:			
Basic	90,423	26,016	19,952
Diluted	90,772	26,086	19,952

See Notes to Consolidated Financial Statements.

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

	Year Ended December 31,		
	2011	2010	2009
Net income	$ 114,664	$ 201,008	$ 141,637
Other comprehensive income (loss):			
Change in value of derivatives	(104,090)	(13,393)	—
Gain on settlement of treasury lock, net of amortization	451	—	—
Adjustment to funded status of benefit plans	(2,843)	(7,019)	—
Total other comprehensive loss	(106,482)	(20,412)	—
Comprehensive income	8,182	180,596	141,637
Less: comprehensive income attributable to noncontrolling interests	(6,163)	(119,647)	(92,043)
Comprehensive income attributable to Buckeye Partners, L.P.	$ 2,019	$ 60,949	$ 49,594

See Notes to Consolidated Financial Statements.

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

	December 31, 2011	December 31, 2010
Assets:		
Current assets:		
Cash and cash equivalents	$ 12,986	$ 13,626
Trade receivables, net	206,601	167,274
Construction and pipeline relocation receivables	8,662	6,803
Inventories	298,304	351,605
Derivative assets	6,756	1,634
Prepaid and other current assets	92,727	85,689
Total current assets	626,036	626,631
Property, plant and equipment, net	3,847,573	2,305,884
Equity investments	65,882	107,047
Goodwill	753,100	432,124
Intangible assets, net	230,568	44,067
Other non-current assets	47,217	58,463
Total assets	$ 5,570,376	$ 3,574,216
Liabilities and partners' capital:		
Current liabilities:		
Line of credit	$ 251,200	$ 284,300
Current portion of long-term debt	—	1,525
Accounts payable	102,445	68,530
Derivative liabilities	1,859	17,285
Accrued and other current liabilities	199,475	144,880
Total current liabilities	554,979	516,520
Long-term debt	2,393,574	1,519,393
Long-term derivative liabilities	101,911	—
Other non-current liabilities	195,955	128,043
Total liabilities	3,246,419	2,163,956
Commitments and contingent liabilities (Note 4)	—	—
Partners' capital:		
Buckeye Partners, L.P. capital:		
Limited Partners (85,968,423 and 71,436,099 units outstanding as of December 31, 2011 and 2010, respectively)	2,035,271	1,413,664
Class B Units (7,304,880 and 0 units outstanding as of December 31, 2011 and 2010, respectively)	395,639	—
Accumulated other comprehensive loss	(127,741)	(21,259)
Total Buckeye Partners, L.P. capital	2,303,169	1,392,405
Noncontrolling interests	20,788	17,855
Total partners' capital	2,323,957	1,410,260
Total liabilities and partners' capital	$ 5,570,376	$ 3,574,216

See Notes to Consolidated Financial Statements.

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

	Year Ended December 31, 2011	2010	2009
Cash flows from operating activities:			
Net income	$ 114,664	$ 201,008	$ 141,637
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sale of equity investment	(34,727)	—	—
Value of ESOP shares released	1,183	4,745	1,641
Depreciation and amortization	119,534	59,590	54,699
Asset impairment expense	—	—	59,724
Goodwill impairment expense	169,560	—	—
Net changes in fair value of derivatives	(66,747)	(45,579)	20,531
Non-cash deferred lease expense	4,122	4,235	4,500
Amortization of unfavorable storage contracts	(7,562)	—	—
Earnings from equity investments	(10,434)	(11,363)	(12,531)
Distributions from equity investments	6,656	14,679	9,660
Equity plan modification expense	—	21,058	—
Amortization of other non-cash items	11,293	5,720	8,257
Change in assets and liabilities, net of amounts related to acquisitions:			
Trade receivables	(29,684)	(43,109)	(44,112)
Construction and pipeline relocation receivables	(1,859)	7,292	7,406
Inventories	102,511	9,955	(177,309)
Prepaid and other current assets	(4,220)	16,368	(28,937)
Accounts payable	29,872	11,808	14,569
Accrued and other current liabilities	(16,312)	30,416	(1,296)
Other non-current assets	17,546	9,528	(9,916)
Other non-current liabilities	(1,504)	(3,872)	(861)
Net cash provided by operating activities	403,892	292,479	47,662
Cash flows from investing activities:			
Capital expenditures	(305,324)	(77,699)	(87,309)
Acquisition of interest in equity investment	(5,723)	(13,512)	—
Contributions to equity investments	—	—	(3,870)
Acquisitions, net of cash acquired	(1,084,469)	(46,915)	(54,443)
Net proceeds for disposal of property, plant and equipment	237	23,938	1,419
Proceeds from the sale of equity investment	85,000	—	—
Net cash used in investing activities	(1,310,279)	(114,188)	(144,203)
Cash flows from financing activities:			
Net proceeds from issuance of units	736,871	—	104,632
Proceeds from exercise of unit options	3,567	4,789	3,204
Issuance of long-term debt	647,530	—	273,210
Repayment of long term-debt	(1,525)	(6,178)	(6,294)
Borrowings under BPL Credit Facility	1,221,732	298,400	317,120
Repayments under BPL Credit Facility	(995,732)	(278,400)	(537,387)
Net borrowings (repayments) under BES Credit Facility	(33,100)	44,500	143,800
Debt issuance costs	(9,968)	(3,551)	(4,691)
Repayment of debt assumed in BORCO acquisition	(318,167)	—	—
Costs associated with agreement and plan of Merger	(1,356)	(16,427)	—
Distributions paid to noncontrolling partners of Buckeye Partners, L.P.	(8,872)	(195,564)	(180,008)
Proceeds from settlement of treasury lock	497	—	—
Distributions paid to partners of Buckeye GP Holdings L.P.	—	(49,808)	(40,752)
Distributions paid to unitholders	(335,730)	—	—
Net cash provided by (used in) financing activities	905,747	(202,239)	72,834
Net decrease in cash and cash equivalents	(640)	(23,948)	(23,707)
Cash and cash equivalents — Beginning of year	13,626	37,574	61,281
Cash and cash equivalents — End of year	$ 12,986	$ 13,626	$ 37,574

See Notes to Consolidated Financial Statements.

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

	Buckeye Partners, L.P. Unitholders							
	General Partner	Limited Partners	Class B Units	Management Units	Equity Gains on Issuance of Buckeye's Limited Partner Units	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
Partners' capital—January 1, 2009	$ 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 LP Units	—	—	—	—	106	—	(106)	—
Net proceeds from issuance of LP Units	—	—	—	—	—	—	104,632	104,632
Amortization of unit-based compensation awards	—	—	—	—	—	—	3,079	3,079
Exercise of 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 unit-based compensation awards	—	2,163	—	—	—	—	6,040	8,203
Exercise of 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)
Other comprehensive income	—	—	—	—	—	17,869	(38,281)	(20,412)
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
Net income	—	100,553	7,948	—	—	—	6,163	114,664
Acquisition of 80% interest in BORCO	—	—	—	—	—	—	276,508	276,508
Acquisition of remaining interest in BORCO	—	—	—	—	—	—	(278,211)	(278,211)
Costs associated with agreement and plan of Merger	—	(1,356)	—	—	—	—	—	(1,356)
Distributions paid to unitholders	—	(341,369)	—	—	—	—	—	(341,369)
Issuance of units to First Reserve for BORCO acquisition	—	152,772	254,619	—	—	—	—	407,391
Issuance of units to Vopak for BORCO acquisition	—	36,041	60,069	—	—	—	—	96,110
Issuance of units to institutional investors	—	350,001	75,000	—	—	—	—	425,001
Equity issuance costs	—	(2,762)	(1,997)	—	—	—	—	(4,759)
Net proceeds from issuance of LP Units in underwritten public offering	—	316,629	—	—	—	—	—	316,629
Amortization of unit-based compensation awards	—	9,233	—	—	—	—	—	9,233
Exercise of LP Unit options	—	3,567	—	—	—	—	—	3,567
Services Company's non-cash ESOP distributions	—	—	—	—	—	—	(1,407)	(1,407)
Distributions paid to noncontrolling interests	—	—	—	—	—	—	(8,872)	(8,872)
Other comprehensive income	—	—	—	—	—	(106,482)	—	(106,482)
Noncash accrual for distribution equivalent rights	—	(1,210)	—	—	—	—	—	(1,210)
Other	—	(492)	—	—	—	—	8,752	8,260
Partners' capital—December 31, 2011	$ —	$ 2,035,271	$ 395,639	$ —	$ —	$ (127,741)	$ 20,788	$ 2,323,957

See Notes to Consolidated Financial Statements.

1. ORGANIZATION

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

We were formed in 1986 and own and operate one of the largest independent refined petroleum products pipeline systems in the United States in terms of volumes delivered with approximately 6,100 miles of pipeline and over 100 active products terminals that provide aggregate storage capacity of approximately 64 million barrels. In addition, we operate and maintain approximately 2,800 miles of third-party 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 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. Our flagship marine terminal in The Bahamas, Bahamas Oil Refining Company International Limited ("BORCO") is one of the largest marine crude oil and petroleum products storage facilities in the world, serving the international markets as a premier global logistics hub.

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

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. 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 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 consolidated financial statements include the accounts of our subsidiaries controlled by us and variable interest entities of which we are the primary beneficiary. We have eliminated all intercompany transactions in consolidation.

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. The fair value of a liability related to the retirement of long-lived assets is 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 terminals that we own and underground refined petroleum products pipelines installed along rights-of-way acquired from land owners and related above-ground facilities. We are unable to predict if and when our pipelines and terminals, 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, which is not significant, will be adjusted prospectively for costs incurred or settled, accretion expense, and any revisions made to the assumptions related to the retirement costs.

Business Combinations

We allocate the total purchase price of a business combination to the assets acquired and the liabilities assumed based on their estimated fair values at the acquisition date, with the excess purchase price recorded as goodwill. For all material acquisitions, we engage an independent valuation specialist to assist us in determining the fair value of the assets acquired and liabilities assumed, including goodwill, based on recognized business valuation methodology. If the initial accounting for the business combination is incomplete by the end of the reporting period in which the acquisition occurs, an estimate will be recorded. Subsequent to the acquisition but not to exceed one year from the acquisition date, we will record any material adjustments retrospectively to the initial estimate based on new information obtained about facts and circumstances that existed as of the acquisition date. Also, we expense any acquisition-related costs as incurred in connection with each business combination. An income, market or cost valuation method may be utilized to estimate the fair value of the assets acquired or liabilities assumed in a business combination. The income valuation method represents the present value of future cash flows over the life of the asset using (i) discrete financial forecasts, which rely on management's estimates of revenue, operating expenses and volumes, (ii) long-term growth rates and (iii) appropriate discount rates. The market valuation method uses prices paid for a reasonably similar asset by other purchasers in the market, with adjustments relating to any differences between the assets. The cost valuation method is based on the replacement cost of a comparable asset at prices at the time of the acquisition reduced for depreciation of the asset.

Business Segments

We operate and report in five business segments: i) Pipelines & Terminals; ii) International Operations; iii) Natural Gas Storage; iv) Energy Services; and v) Development & Logistics. Effective January 1, 2011, we realigned our business segments. We combined our former Pipeline Operations and Terminalling & Storage segments into one segment, the Pipelines & Terminals segment, and moved our terminal in Yabucoa, Puerto Rico, previously included as part of the Terminalling & Storage segment, to a new International Operations segment with the BORCO facility. We have adjusted our prior period segment information to conform to the current presentation. See Note 25 for a more detailed discussion of our business segments.

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, 2011, 2010 and 2009 was $7.6 million, $2.5 million and $3.4 million, respectively. The weighted average rates used to capitalize interest on borrowed funds was 4.2%, 4.8% and 5.4% for the years ended December 31, 2011, 2010 and 2009, 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.

Comprehensive Income

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

Concentration of Credit Risk and Trade Receivables

Trade receivables are primarily due from oil and gas companies, refineries, marketing and trading companies, and commercial airlines. These concentrations of customers may affect our overall credit risk as these customers may be similarly affected by changes in economic, regulatory or other factors. We extend credit to customers and manage our credit risks through credit analysis and monitoring procedures, including credit approvals, credit limits and right of offset. Also, we manage our risk using letters of credit, prepayments and guarantees.

Trade receivables represent valid claims against non-affiliated customers and are recognized when products are sold or services are rendered. We record an allowance for doubtful accounts for estimated losses resulting from the inability of our customers to make required payments. We review the adequacy of the allowance for doubtful accounts monthly by making judgments regarding future events and trends based on the (i) customers' historical relationship with us, (ii) customers' current financial condition, and (iii) current and projected economic conditions. The activity in the allowance for doubtful accounts is as follows at the dates indicated (in thousands):

	December 31,		
	2011	2010	2009
Balance at beginning of period	$ 2,893	$ 1,544	$ 2,083
Charged to expense	200	4,868	350
Write-offs, net of recoveries	(745)	(3,519)	(889)
Balance at end of period	$ 2,348	$ 2,893	$ 1,544

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 loss has been incurred and the amount of liability can be estimated, then the estimated liability is 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. Actual results could vary from these estimates and judgments.

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 natural 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 natural gas from a third party is injected and stored for a specified period. The third party then is obligated to withdraw its stored natural gas at a future date. Title to the natural gas remains with the third party. Loans occur when natural gas is delivered to a third party in a specified period. The third party then has the obligation to redeliver natural 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. See Note 10 and 12 for more information on debt issuance costs.

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 forecasted 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 accumulated other comprehensive income to earnings when the forecasted transaction occurs and affects net income or, as appropriate, over the economic life of the underlying asset or liability. A derivative instrument designated as a hedge of an forecasted 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 Unit

Basic earnings per unit, which includes LP Units and Class B Units (as defined in Note 21), is determined by dividing our net income, after deducting the amount allocated to noncontrolling interests, by the weighted average units outstanding for the period. Diluted earnings per unit is calculated the same way except the weighted average 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 18 for more information. Amounts reflecting historical BGH unit and per unit amounts included in this report have been restated for the reverse unit split.

Environmental Expenditures

We are subject to federal, state and local laws and regulations relating to the protection of the environment. These laws and regulations require us to remove or remedy the effect of the disposal or release of specified substances at our operating sites. We record environmental liabilities at a specific site when environmental assessments occur or remediation efforts are probable and can be reasonably estimated based upon past experience, discussions with operating personnel, advice of outside engineering or consulting firms, discussions with general counsel or current facts and circumstances. 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. Our estimated environmental remediation liabilities are not 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 monitor the environmental liabilities regularly and record adjustments to our initial estimates, from time to time, to reflect changing circumstances and estimates based upon additional developments or information obtained in subsequent periods. We maintain insurance which may cover certain environmental expenditures. Recoveries of environmental remediation expenses from other parties are recorded when their receipt is deemed probable.

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 total investment exceeds the proportionate share of the book value of the net assets of the investment. Such excess investment not related to any specific accounts of the investee are treated as goodwill and not amortized. Amounts associated with specific accounts of the investee are amortized. 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, 2011, 2010 or 2009.

Estimates

The preparation of consolidated financial statements in conformity with GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses during the reporting period and disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Actual results could differ from our estimates.

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 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 characteristics of fair value amounts classified within each level of the hierarchy are described as follows:

- Level 1 inputs – unadjusted quoted prices which are available in active markets for identical, unrestricted assets or liabilities as of the reporting date;
- Level 2 inputs – quoted market prices in market that are not considered to be active or financial instruments for which all significant inputs are observable, either directly or indirectly; and
- Level 3 inputs – prices or valuations that require inputs that are both significant to the fair value measurement and unobservable. These inputs are typically used in connection with internally developed valuation methodologies where management makes its best estimate of an instrument's fair value.

At each balance sheet reporting date, we categorize our financial assets and liabilities using this hierarchy.

Cash and cash equivalents, prepaid and other current assets and accrued and other 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. The fair values of our aggregate debt and credit facility were estimated to be $2,811.7 million and $1,897.5 million at December 31, 2011 and 2010, respectively. Also, we utilize forward-starting interest rate swaps to manage our interest rate risk related to forecasted interest payments on anticipated debt issuances. We have derivative assets and liabilities that 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 fair value of derivatives.

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.

We may perform a qualitative assessment to determine whether the fair value of our reporting units are more likely than not less than the carrying amount. If we believe the fair value is less than the carrying amount, we will perform step one of the two-step goodwill impairment test. See "*Recent Accounting Developments*" below. The first step of the goodwill impairment test determines whether an impairment exists by comparing the fair value of a reporting unit with its carrying amount, including goodwill. If the estimated fair value of the reporting unit exceeds its carrying amount, no impairment is necessary. If the carrying amount of a reporting unit exceeds its estimated fair value, the second step measures the amount of impairment by comparing the implied fair value of the reporting unit goodwill with the carrying amount of that goodwill. We would assign the fair value of a reporting unit to all of the assets and liabilities of that unit as if the reporting unit had been acquired in a business combination. The excess of the fair value of a reporting unit over the amounts assigned to its assets and liabilities is the implied fair value of goodwill. The estimate of the fair value of the reporting unit is determined using a combination of an expected present value of future cash flows and a market multiple valuation method. The present value of future cash flows is estimated using (i) discrete financial forecasts, which rely on management's estimates of revenue, operating expenses and volumes, (ii) long-term growth rates and (iii) appropriate discount rates. The market multiple valuation method uses appropriate market multiples from comparable companies on the reporting unit's earnings before interest, tax, depreciation and amortization. We evaluate industry and market conditions for purposes of weighting the income and market valuation approach.

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. Our operations at the BORCO facility are not subject to income taxes by the Bahamian government. Our operations at the Yabucoa terminal are subject to income taxes within the Commonwealth of Puerto Rico.

We recognize deferred tax assets and liabilities for temporary differences between the amounts of assets and liabilities measured for financial reporting purposes and federal income tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. We evaluate the need for a valuation allowance and consider all available positive and negative evidence, including the projected operating losses for the foreseeable future, to determine the likelihood of realizing the benefits of deferred tax assets. If the value of the deferred tax assets exceeds the estimated future benefit, we record a valuation allowance to reduce our deferred tax assets to the amount of future benefit that is more likely than not to be realized. In the future, if the realization of the deferred tax assets should occur, a reduction to the valuation allowance related to the deferred tax assets would increase net income in the period such determination is made.

As of December 31, 2011 and 2010, our carrying amount of net assets in BDL exceeded our tax basis. As we determined that the deferred tax asset of approximately $0.3 million for BDL is not expected to be realized, we have provided a full valuation allowance against the deferred tax assets as of December 31, 2011. As of December 31, 2011 and 2010, we had deferred tax assets of $35.0 million related to Buckeye Caribbean Terminals LLC ("Buckeye Caribbean"), of which approximately $17.2 million and $15.2 million primarily relate to property, plant and equipment and net operating loss carryforwards, respectively. Unless utilized, the tax benefits of the net operating loss carryforwards will expire between 2018 and 2020. Based on available evidence, we recorded a full valuation allowance against these deferred tax assets upon acquisition during the year ended December 31, 2010. There were no significant changes in our judgment during the year ended December 31, 2011 and we continue to carry a full valuation allowance against the deferred tax assets.

During the year ended December 31, 2011, Buckeye Caribbean underwent an audit of its Puerto Rico income tax returns for the tax years 2002 through 2005. The Puerto Rico Treasury Department completed the audit of such years and informed us that no adjustment was required to the taxable income or losses reported on such years. However, the Puerto Rico Treasury Department has notified the entity of a certain area for discussion on the 2008 taxable year related to the possible recapture of investment tax credits previously granted to affiliates of Royal Dutch Shell plc ("Shell") but no preliminary or final notice of debt regarding such issue has been issued. In the 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 Notes 10 and 13 for further information.

Income tax benefits of $0.2 million, $0.9 million and $0.3 million for the years ended December 31, 2011, 2010 and 2009, respectively, were recorded in operating expenses in the consolidated statements of operations.

Intangible Assets

Intangible assets with finite useful lives are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Intangible assets that have finite useful lives are amortized over their useful lives. Intangible assets include contracts and customer relationships. The fair values of these intangibles are based on the present value of cash flows attributable to the customer relationship or contract, which includes management's estimates of revenue and operating expenses and costs relating to utilization of other assets to fulfill such contracts. The customer contracts are being amortized over their contractual lives with a weighted average of approximately 5 years. For the customer relationships, we determine the recovery period based on historical customer attrition rates and management's assumptions on future events, including customer demand, contract renewal and market conditions. The customer relationships are being amortized over the estimated recovery period of 12 to 20 years. When necessary, intangible assets' useful lives are revised and the impact on amortization is reflected on a prospective basis.

Inventories

We generally maintain two types of inventory. Our Energy Services segment principally maintains refined petroleum products inventory, consisting of gasoline, ethanol, heating oil, bio diesel and diesel fuel. Inventory is valued at the lower of cost or market using the weighted average costs method, unless such inventories are hedged. Hedged inventory is adjusted for the effects of applying fair value hedge accounting.

We also maintain, principally within our Pipelines & Terminals 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.

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 determine the estimated undiscounted future cash flows expected to result from the use of the asset and its eventual disposal. If the sum of the estimated undiscounted future cash flows exceeds the carrying amount, no impairment is necessary. If the carrying amount exceeds the sum of the undiscounted cash flows, an impairment charge is recognized based on 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. Estimates of future undiscounted net cash flows are based on discrete financial forecasts, which rely on management's estimates of revenue, 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.

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 our net income to LP Unitholders, Class B Unitholders and noncontrolling interests.

Noncontrolling Interests

The consolidated balance sheets and statements of operations include noncontrolling interests that relate primarily to Services Company and portions of Sabina Pipeline and WesPac Pipelines – Memphis LLC ("WesPac Memphis") that are not owned by Buckeye. Additionally, the remaining 20% interest of FR Borco Coop Holdings, L.P. ("FRBCH") represented noncontrolling interests until we acquired such interest from Vopak Bahamas B.V. ("Vopak") on February 16, 2011. Prior to the Merger, noncontrolling interests reported by BGH also included equity interests in Buckeye that were not owned by BGH.

Pensions and Postretirement Benefits

Services Company sponsors a defined contribution plan, a defined benefit plan and the Employee Stock Ownership Plan ("ESOP") that provide retirement benefits to certain regular full-time employees and an unfunded post-retirement plan that provides health care and life insurance benefits for certain of its retirees. Certain employees of Services Company are covered by a defined contribution plan or health and welfare plan under a union agreement. We develop pension, postretirement health care and life insurance benefits costs from actuarial valuations. The measurement of expenses and liabilities related to these plans is based on management's assumptions related to future events, including expected return on plan assets, rate of compensation increase, and heath care cost trend rates. The actuarial assumptions that we use may differ from actual results due to changing market rates or other factors. These differences could affect the amount of pension and postretirement health care and life insurance benefit expense we have recorded or may record.

Property, Plant and Equipment

We record property, plant and equipment at its original acquisition cost. Property, plant and equipment consist primarily of pipelines, storage and terminal facilities, jetties and subsea pipelines, pad gas and pumping and station equipment. Generally, we depreciate property, plant and equipment based on the straight-line method over the estimated useful lives, except for pad gas. The Natural Gas Storage segment maintains a level of natural gas in its underground storage facility generally known as pad gas, which is not routinely cycled but, instead, serves the function of maintaining the necessary pressure to allow routine injection and withdrawal to meet demand. The pad gas is considered to be a component of the facility and as such is not depreciated because it is expected to ultimately be recovered and sold. See Note 7 for the depreciation life of our assets.

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.

Recent Accounting Developments

Intangibles, Goodwill and Other. In September 2011, the FASB issued guidance that amended testing goodwill for impairment. Under the revised guidance, entities testing goodwill for impairment have the option of performing a qualitative assessment before calculating the fair value of the reporting unit (i.e., step 1 of the goodwill impairment test). If entities determine, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not less than the carrying amount, the two-step impairment test would be required. The amended guidance does not change how goodwill is calculated or assigned to reporting units nor revise the requirement to test goodwill for impairment annually or between annual tests if events or circumstances warrant. However, it does revise the examples of events and circumstances that an entity should consider. The amendments are effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. We applied the amended guidance for our annual goodwill impairment testing of our reporting units as of January 1, 2012. See Note 9 for more information. The adoption of this guidance did not have an impact on our consolidated financial statements.

Reclassifications

Reclassifications relate to components of intangible assets and other comprehensive income and providing additional categories within property, plant and equipment and prepaid and other current assets to conform to the 2011 presentation. Such reclassifications have no impact on net income or partners' capital.

Revenue Recognition

Pipelines & Terminals 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 product 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.

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.

International Operations segment. Revenues from terminalling, storage and rental operations at our Yabucoa, Puerto Rico and BORCO terminal are recognized as the services are performed as discussed above. Rental fees, which represents fees charged for storage of crude oil and other products, is recognized ratably over the term of the respective contract. Customers are generally charged a rental fee based on committed gross tank capacity.

Revenue from berthing fees and other ancillary services is recognized in the accounting period in which the services are rendered. Berthing fees represent amounts charged to ships that utilize BORCO's jetties.

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

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, which consist of Value B, Value N-1 and Value N-2 Units. The vesting of these override units is contingent on a performance condition, namely the completion of the exit event (as defined in Note 18), and a market condition, primarily relating to the receipt of an investment return at a specified multiple and internal rate of return, where applicable. Accordingly, no compensation expense for these override units will be recorded until, and if, an exit event and other requirements occur.

We also award unit-based compensation to employees and directors primarily under the LTIP. We formerly awarded options to acquire LP Units to employees pursuant to the Buckeye Partners, L.P. Unit Option and Distribution Equivalent Plan (the "Option Plan"). 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. 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.

3. ACQUISITIONS AND DISPOSITIONS

Business Combinations

The following acquisitions were accounted for as business combinations:

2011 Transactions

On July 19, 2011, we acquired, from an affiliate of ExxonMobil Corporation ("ExxonMobil") for $23.5 million in cash, a terminal in Bangor, Maine ("Bangor Terminal") with approximately 140,000 barrels of storage capacity, a terminal in Portland, Maine ("South Portland Terminal") with approximately 725,000 barrels of storage capacity through a 50/50 joint venture with Irving Oil Terminals Inc. and a 124-mile pipeline that connects the two terminals. We believe this acquisition represents our efforts to diversify into new geographic regions and to increase our marine terminals presence. The South Portland terminal is operated by our Development & Logistics segment. We account for the South Portland terminal using the equity method of accounting. See Note 8 for equity investment information. The pipeline, Bangor Terminal and equity investment are reported in the Pipelines & Terminals segment. We financed this acquisition with borrowings under our Prior BPL Credit Facility (as defined in Note 12). The purchase price was allocated principally to property, plant, and equipment and equity method investment.

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

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

On December 18, 2010, we, through a wholly owned subsidiary, entered into a sale and purchase agreement with affiliates of FRC Founders Corporation ("First Reserve"), pursuant to which we agreed to acquire First Reserve's indirect 80% interest in FRBCH, the indirect owner of BORCO, for $1.15 billion, financed through a combination of debt and equity, including the issuance of Class B Units and LP Units to First Reserve. BORCO is the fourth largest marine crude 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. The acquisition of this world-class terminal facility allows us to expand and diversify our operations by reaching beyond the continental United States and complements our existing portfolio of assets. On January 18, 2011, we completed the purchase of First Reserve's interest in BORCO through the acquisition by us of all of the partnership interests in FR Borco Topco, L.P., which indirectly owned First Reserve's interest.

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

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

Total proceeds from this offering, after underwriters' fees, expenses and debt issuance costs of $4.9 million, were approximately $642.6 million, and were used to fund a portion of the purchase price of the BORCO acquisition.

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

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

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

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

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

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

We recorded goodwill, which represents both expected synergies from combining this terminal facility with our existing operations and the economic value attributable to future expansion projects resulting from this acquisition. We allocated negative fair values to certain unfavorable storage contracts at the date of acquisition and recorded them as current and long-term liabilities in the consolidated balance sheet (see Note 11 and Note 13). The unfavorable storage contracts are being recognized to revenue based on the estimated realization of the fair value established on the acquisition date over the contractual life. Fair values have been developed using recognized business valuation methodology. The operations of this terminal facility are reported in the International Operations segment. The purchase price has been allocated to tangible and intangible assets acquired and liabilities assumed as follows (in thousands):

Current Assets	$ 40,842
Inventory	1,645
Property, plant and equipment	1,129,961
Intangible assets	191,000
Other assets	415
Goodwill	490,536
Current liabilities	(54,627)
Debt	(318,167)
Other liabilities	(57,418)
Allocated purchase price	$ 1,424,187

2010 Transaction

On December 10, 2010, we, through a wholly owned subsidiary, acquired a refined petroleum products terminal in Yabucoa, Puerto Rico through the acquisition of a Puerto Rico entity from an affiliate of Shell for $32.8 million, net of cash acquired of $3.5 million. The terminal includes 44 storage tanks with approximately 4.6 million barrels of gasoline, jet fuel, diesel, fuel oil and crude oil storage capacity. Shell entered into a commercial contract with us concurrent with the acquisition regarding usage of the acquired facility. The operations of these acquired assets are reported in the International Operations segment. The purchase price has been allocated to tangible and intangible assets acquired and liabilities assumed as follows (in thousands):

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

2009 Transaction

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 Pipelines & Terminals segment. 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

Unaudited Pro forma Financial Results

Our consolidated statements of operations do not include earnings from BORCO prior to January 18, 2011, the effective date of the BORCO acquisition. The total revenue and net income for BORCO since the acquisition date of $177.6 million and $66.4 million, respectively, were included in our consolidated statement of operations for the year ended December 31, 2011. The following table presents selected unaudited pro forma earnings information for the years ended December 31, 2011, and 2010, as if the BORCO acquisition had occurred on January 1, 2010. This pro forma information does not give effect to any of the other acquisitions we have made since January 1, 2010, as pro forma results including those acquisitions would not be materially different from the information presented in our accompanying consolidated statements of operations. The pro forma information presented below was prepared using BORCO's historical financial data and reflects certain estimates and assumptions made by our management. Our unaudited pro forma financial information was prepared for comparative purposes only and is not necessarily indicative of what our consolidated financial results would have been had we actually acquired BORCO on January 1, 2010 or the results that may be attained in the future (in thousands):

	(Unaudited) Year Ended December 31, 2011	2010
Revenue:		
As reported	$ 4,759,610	$ 3,151,268
Pro forma adjustments	8,422	193,120
Pro forma revenue	$ 4,768,032	$ 3,344,388
Net income :		
As reported	$ 114,664	$ 201,008
Pro forma adjustments	3,231	36,400
Pro forma net income	$ 117,895	$ 237,408

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, 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.

Dispositions

On May 11, 2011, we sold our 20% interest in West Texas LPG Pipeline Limited Partnership ("WT LPG") to affiliates of Atlas Pipeline Partners L.P. for $85.0 million. WT LPG owns approximately 2300-mile common-carrier pipeline system that transports natural gas liquids from points in New Mexico and Texas to Mont Belvieu, Texas for fractionation. Chevron Pipeline Company, which owns the remaining 80% interest, is the operator of WT LPG. The proceeds from the sale were used to fund a portion of our internal growth capital projects in 2011. We recognized a gain of $34.7 million on the sale of our interest in WT LPG.

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 7 for further discussion.

4. COMMITMENTS AND CONTINGENCIES

Claims and Legal 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.

Environmental Contingencies

We recorded operating expenses, net of recoveries, of $14.0 million, $8.5 million, and $10.6 million during the years ended December 31, 2011, 2010, and 2009, respectively, related to environmental expenditures unrelated to claims and legal proceedings. As of December 31, 2011 and 2010, we recorded environmental liabilities of $58.4 million and $30.8 million, respectively (see Notes 11 and 13). Costs incurred may be in excess of our estimate, which may have a material impact our financial condition, results of operations or cash flows.

Ammonia Contract Contingencies

On November 30, 2005, BDL 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 supply costs exceeding ammonia sales proceeds. The amount of the shortfall generally increases as the market price of ammonia increases.

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

Leases –Where We are Lessee

We lease certain property, plant and equipment under noncancelable and cancelable operating leases. Rental 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, 2011, 2010, and 2009 was $30.1 million, $21.3 million, and $21.2 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	Equipment (1)	Land Leases (2)	Total
2012	$ 2,443	$ 3,487	$ 5,672	$ 11,602
2013	2,589	3,608	5,799	11,996
2014	2,690	2,093	5,882	10,665
2015	2,768	—	6,006	8,774
2016	2,869	—	6,149	9,018
Thereafter	14,247	—	384,949	399,196
Total	$ 27,606	$ 9,188	$ 414,457	$ 451,251

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

(2) Includes leases the for inland dock and seabed in connection with our operations in the International Operations segment and 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. Rental expense associated with these leases, which is being recognized on a straight-line basis over 44 years, was approximately $7.1 million, $7.1 million and $7.4 million for the years ended December 31, 2011, 2010 and 2009, respectively. At December 31, 2011 and 2010, the balance of our Natural Gas Storage segment deferred lease liability increased by $4.1 million and $4.2 million, respectively, to $17.5 million and $13.3 million, respectively in the years ended December 31, 2011 and 2010. 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.

Additionally, our Right-of-way payments were approximately $6.6 million for the year ended December 31, 2011 and are subject to an annual escalation for the remaining life of all pipelines and terminals.

Leases – Where We are Lessor

We have entered into capacity leases with remaining terms from 1 to 15 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 are as follows (in thousands):

	Years Ending December 31,
2012	$ 136,877
2013	82,507
2014	17,371
2015	16,782
2016	16,309
Thereafter	72,855
Total	$ 342,701

5. INVENTORIES

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

	December 31, 2011	December 31, 2010
Refined petroleum products (1)	$ 285,509	$ 340,659
Materials and supplies	12,795	10,946
Total inventories	$ 298,304	$ 351,605

(1) Ending inventory was 99.6 million and 134.9 million gallons of refined petroleum products at December 31, 2011 and 2010, respectively.

At December 31, 2011 and 2010, approximately 96% and 94%, respectively, of our refined petroleum products inventory volumes were hedged. Because we generally designate inventory as a hedged item upon purchase, 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 the lower of cost or market using the weighted average cost method.

6. PREPAID AND OTHER CURRENT ASSETS

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

	December 31, 2011	December 31, 2010
Prepaid insurance	$ 12,028	$ 8,865
Insurance receivables related to environmental expenditures	12,724	8,886
Ammonia receivable	1,288	1,295
Margin deposits	9,871	18,833
Prepaid services	8,661	24,359
Unbilled revenue	10,090	3,263
Tax receivable	1,610	120
Prepaid taxes	1,677	5,417
Vendor prepaid	14,903	2,657
Other	19,875	11,994
Total prepaid and other current assets	$ 92,727	$ 85,689

7. PROPERTY, PLANT AND EQUIPMENT

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

	Estimated Useful Lives (Years)	December 31, 2011	December 31, 2010
Land	N/A	$ 226,750	$ 64,905
Rights-of-way	(1)	109,325	97,529
Pad gas	N/A	29,346	29,346
Buildings and leasehold improvements	13-50	147,454	109,585
Jetties and subsea pipelines	20-50	336,431	—
Gas storage facility	25-50	206,237	196,077
Pipelines and terminals	7-50	2,947,643	1,982,049
Vehicles, equipment and office furnishings	3-20	83,765	72,901
Construction in progress	N/A	178,756	66,642
Total property, plant and equipment		4,265,707	2,619,034
Less: Accumulated depreciation		(418,134)	(313,150)
Total property, plant and equipment, net		$ 3,847,573	$ 2,305,884

(1) Rights-of-way assets are depreciated over the term of the agreement.

Depreciation expense was $105.5 million, $54.7 million and $50.9 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Impairment of Long-Lived Assets

We previously 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 had recently gone 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 Pipelines & Terminals segment.

We ceased depreciation of the assets as of July 1, 2009 and reclassified the assets of Buckeye NGL to "Assets held for sale". 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.

8. EQUITY INVESTMENTS

The following table presents our equity investments, all included within the Pipelines & Terminals segment, at the dates indicated (in thousands):

	Ownership	December 31, 2011	December 31, 2010
Muskegon Pipeline LLC	40.0%	$ 14,302	$ 14,552
Transport4, LLC	25.0%	481	341
West Shore Pipe Line Company (1)	34.6%	44,987	43,563
West Texas LPG Pipeline Limited Partnership (2)	—	—	48,591
South Portland Terminal LLC (3)	50.0%	6,112	—
Total equity investments		$ 65,882	$ 107,047

(1) In August 2010, we acquired additional shares, which increased our interest from 24.9% to 34.6%. See Note 3 for further information.
(2) In May 2011, we sold our 20.0% interest. See Note 3 for further information.
(3) In July 2011, we acquired a 50.0% interest. See Note 3 for further information.

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

	Year Ended December 31, 2011	2010	2009
Muskegon Pipeline LLC	$ 958	$ 1,482	$ 1,437
Transport4, LLC	185	162	147
West Shore Pipe Line Company (1)	6,605	4,988	4,809
West Texas LPG Pipeline Limited Partnership (2)	2,297	4,731	6,138
South Portland Terminal LLC (3)	389	—	—
Total earnings from equity investments	$ 10,434	$ 11,363	$ 12,531

(1) In August 2010, we acquired additional shares, which increased our interest from 24.9% to 34.6%. See Note 3 for further information.
(2) In May 2011, we sold our 20.0% interest. See Note 3 for further information.
(3) In July 2011, we acquired a 50.0% interest. See Note 3 for further information.

Summarized combined unaudited financial information for our equity method investments are as follows for the periods indicated (amounts represent 100% of investee financial information in thousands):

	December 31, 2011(1)	December 31, 2010
BALANCE SHEET DATA:		
Current assets	$ 24,338	$ 30,905
Noncurrent assets	62,305	206,076
Total assets	$ 86,643	$ 236,981
Current liabilities	$ 17,531	$ 34,825
Other liabilities	23,507	9,111
Combined equity	45,605	193,045
Total liabilities and combined equity	$ 86,643	$ 236,981

	Year Ended December 31,		
	2011(1)	2010	2009
INCOME STATEMENT DATA:			
Revenue	$ 100,931	$ 139,355	$ 134,786
Costs and expenses	53,596	79,584	67,694
Non-operating expense	13,708	12,290	12,914
Net income	$ 33,627	$ 47,481	$ 54,178

(1) In May 2011, we sold our 20.0% interest in WT LPG; therefore, the respective balance sheet data is not presented, however the income statement data includes activity through the sale. See Note 3 for further information.

9. GOODWILL AND INTANGIBLE ASSETS

Goodwill

The changes in the carrying amount of goodwill by segment are as follows at the dates indicated (in thousands):

	Pipelines & Terminals	International Operations	Natural Gas Storage	Energy Services	Development & Logistics	Total
December 31, 2010	$ 248,250	$ —	$ 169,560	$ 1,132	$ 13,182	$ 432,124
Acquisition	—	490,536	—	—	—	490,536
Impairment charge	—	—	(169,560)	—	—	(169,560)
December 31, 2011	$ 248,250	$ 490,536	$ —	$ 1,132	$ 13,182	$ 753,100

During 2011, we concluded the continued downward performance in operating income and Adjusted EBITDA (as defined in Note 25) in the Natural Gas Storage segment due to decreases in contracted storage prices relating to low volatility in natural gas prices and compressed seasonal spreads was an impairment indicator; therefore, we performed an interim goodwill impairment test. The estimate of the fair value of the Natural Gas Storage reporting unit was determined using a combination of an expected present value of future cash flows and a market multiple valuation method. Due to the current market conditions, we weighted 100% to the expected present value of future cash flows method.

Our Natural Gas Storage reporting unit failed the first step of the goodwill impairment test; therefore, we performed the second step. As a result of our step two analysis, we concluded goodwill in the Natural Gas Storage segment was fully impaired and recorded a non-cash goodwill impairment charge of $169.6 million in the third quarter of 2011. We considered the goodwill impairment an indicator of impairment related to the long-lived assets associated with the Natural Gas Storage reporting unit. Accordingly, we evaluated these assets for impairment and concluded that no impairment of the long-lived asset existed.

For our annual goodwill impairment test as of January 1, 2012, we performed a qualitative assessment to determine whether the fair value of the Pipelines & Terminals reporting unit was more likely than not less than the carrying amount based on economic conditions and industry and market considerations. We determined the fair value of the reporting unit exceeded the carrying amount; therefore, the two-step impairment test was not required. For the other reporting units, we calculated the fair value of each of the remaining reporting units. Based on such calculations, each reporting unit's fair value was in excess of its carrying value. We did not record any goodwill impairments for the years ended December 31, 2010 and 2009.

Intangible Assets

Intangible assets consist of the following at the dates indicated (in thousands):

	December 31,	
	2011	2010
Customer relationships	$229,300	$38,300
Accumulated amortization	(18,839)	(8,600)
Net carrying amount	210,461	29,700
Customer contracts	28,683	19,743
Accumulated amortization	(8,576)	(5,376)
Net carrying amount	20,107	14,367
Total intangible assets	$230,568	$44,067

We anticipate the customer relationships with the BORCO facility will extend well beyond the existing contractual terms with a recovery period of approximately 20 years after taking into consideration the following: i) the expected useful life of the relationships approximates the useful life of the storage tanks used to serve these customers; ii) the facility is the fourth largest marine crude oil and petroleum products storage terminal in the world and the largest in the Caribbean, strategically positioned to facilitate international logistics and provides full terminalling services to customers; iii) the facility currently has a long term agreement with the Bahamian government to lease 330 acres of seabed on which our jetties are located through 2057; and iv) historically low customer attrition related to this facility. We believe amortizing the customer relationships on a straight-line basis is appropriate as it approximates the deprecation method applied to the storage tanks.

For the years ended December 31, 2011, 2010 and 2009, amortization expense related to intangible assets was $13.4 million, $4.5 million and $3.5 million, respectively. Amortization expense related to intangible assets is expected to be approximately $14.6 million for 2012, $14.6 million for 2013, $14.4 million for 2014, $13.4 million for 2015 and $11.7 million for 2016.

10. OTHER NON-CURRENT ASSETS

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

	December 31,	
	2011	2010
Prepaid services	$ 978	$ 5,836
Unbilled revenue	25	2,163
Derivative assets	—	3,892
Debt issuance costs, net	14,431	11,184
Insurance receivables related to environmental expenditures	4,740	8,826
Indemnification asset (see Note 2)	17,720	17,720
Other	9,323	8,842
Total other non-current assets	$ 47,217	$ 58,463

11. ACCRUED AND OTHER CURRENT LIABILITIES

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

	December 31, 2011	December 31, 2010
Taxes—other than income	$ 26,227	$ 20,698
Accrued employee benefit liabilities	3,071	3,817
Environmental liabilities (1)	12,587	10,471
Interest payable	44,072	30,700
Payable for ammonia purchase	2,121	2,354
Unearned revenue	8,128	18,776
Compensation and vacation	17,353	13,134
Accrued capital expenditures	16,328	2,032
Unfavorable storage contracts (2)	10,994	—
Deferred consideration	1,000	2,010
Customer deposits	13,687	5,389
Other	43,907	35,499
Total accrued and other current liabilities	$ 199,475	$ 144,880

(1) Amount for 2011 includes environmental liabilities acquired in connection with the BORCO and BP acquisitions. See Note 3 for further information on the respective acquisitions.
(2) See Note 3 for a discussion of the unfavorable storage contracts acquired in connection with the BORCO acquisition.

12. LONG-TERM DEBT

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

	December 31, 2011	December 31, 2010
4.625% Notes due July 15, 2013 (1)	$ 300,000	$ 300,000
5.300% Notes due October 15, 2014 (1)	275,000	275,000
5.125% Notes due July 1, 2017 (1)	125,000	125,000
6.050% Notes due January 15, 2018 (1)	300,000	300,000
5.500% Notes due August 15, 2019 (1)	275,000	275,000
4.875% Notes due February 1, 2021 (1)	650,000	—
6.750% Notes due August 15, 2033 (1)	150,000	150,000
BPL Credit Facility (2)	575,200	98,000
BES Credit Facility	—	284,300
Services Company 3.60% ESOP Notes due March 28, 2011	—	1,531
Retirement premium	—	(6)
Total debt	2,650,200	1,808,825
Other, including unamortized discounts	(5,426)	(3,607)
Subtotal debt	2,644,774	1,805,218
Less: Current portion of long-term debt and line of credit (3)	(251,200)	(285,825)
Total long-term debt	$ 2,393,574	$ 1,519,393

(1) We make semi-annual interest payments on these notes based on the rates noted above with the principal balances outstanding to be paid on or before the due dates as shown above.
(2) Includes the Credit Facility and Prior BPL Credit Facility as defined below.
(3) The line of credit is classified as a current liability in our consolidated balance sheets as related funds are used to finance BES's current working capital needs.

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,
2012	$ 251,200
2013	300,000
2014	275,000
2015	—
2016	324,000
Thereafter	1,500,000
Total	$ 2,650,200

Notes Offerings

On January 13, 2011, we sold the 4.875% Notes in an underwritten public offering. The notes were issued at 99.62% of their principal amount. Total proceeds from this offering, after underwriters' fees, expenses and debt issuance costs of $4.9 million, were approximately $642.6 million, and were used to fund a portion of the purchase price for our acquisition of BORCO (see Note 3). In connection with this offering, we settled a treasury lock agreement, which resulted in the receipt of a settlement of $0.5 million, which is being amortized as a reduction to interest expense over the ten-year term of the 4.875% Notes (see Note 15).

Bridge Loans

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

Services Company ESOP Notes

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

Credit Facility

On September 26, 2011, Buckeye and its indirect wholly-owned subsidiary, Buckeye Energy Services LLC ("BES"), as borrowers, entered into a Revolving Credit Agreement (the "Credit Facility") with SunTrust Bank, as administrative agent and other lenders to provide for a $1.25 billion senior unsecured revolving credit agreement of which we have a borrowing capacity of $1.25 billion and BES has a sublimit of $500.0 million. The Credit Facility's maturity date is September 26, 2016, with an option to extend the term for two successive one-year periods and a $500.0 million accordion option to increase the commitments. Concurrently with the execution of the Credit Facility, Buckeye and BES borrowed $242.3 million and $320.2 million, respectively, and used the proceeds to repay all amounts outstanding under Buckeye's senior unsecured revolving credit agreement dated November 13, 2006 (the "Prior BPL Credit Facility") and BES's amended and restated senior revolving credit agreement dates as of June 25, 2010 (the "BES Credit Facility"), respectively, and customary fees and expenses related to the Credit Facility. Buckeye and BES incurred debt issuance costs of approximately $3.6 million and $1.4 million, respectively, related to the Credit Facility. These costs were included in other non-current assets and are being amortized over the Credit Facility terms of five years.

Under the Credit Facility, interest accrues on advances at a LIBOR rate or a base rate plus an applicable margin based on the election of the applicable borrower for each interest period. The issuing fees for all letters of credit are also based on an applicable margin. The applicable margin used in connection with interest rates and fees is based on the credit ratings assigned to our senior unsecured long-term debt securities. The applicable margin for LIBOR rate loans, swing line loans, and letter of credit fees ranges from 1.0% to 1.75% and the applicable margin for base rate loans ranges from 0% to 0.75%. Buckeye and BES will also pay a fee based on our credit ratings on the actual daily unused amount of the aggregate commitments. At December 31, 2011, Buckeye and BES had $575.2 million in aggregate outstanding under the Credit Facility, of which BES classified $251.2 million as a current liability in our consolidated balance sheets as related funds are used to finance current working capital needs. The weighted average interest rate for borrowings under the Credit Facility was 1.7% at December 31, 2011.

The Credit Facility includes covenants limiting, as of the last day of each fiscal quarter, the ratio of consolidated funded debt ("Funded Debt Ratio") to consolidated EBITDA, as defined in the Credit Facility, measured for the preceding twelve months, to not more than 5.00 to 1.00. This requirement is subject to a provision for increases to 5.50 to 1.00 in connection with certain future acquisitions. The Funded Debt Ratio is calculated by dividing consolidated debt by annualized EBITDA, which is defined in the Credit Facility as earnings before interest, taxes, depreciation, depletion and amortization determined on a consolidated basis. At December 31, 2011, our Funded Debt Ratio was approximately 4.6 to 1.00. At December 31, 2011, we were in compliance with the covenants under our Credit Facility.

At December 31, 2011 and 2010, we had committed $1.5 million and $1.4 million, respectively, in support of letters of credit. The obligations for letters of credit are not reflected as debt on our consolidated balance sheets.

Prior BPL Credit Facility

The Prior BPL Credit Facility provided a borrowing capacity of $580.0 million under an unsecured revolving credit agreement, which could have expanded up to $780.0 million subject to certain conditions and upon the further approval of the lenders. The Prior BPL Credit Facility had a maturity date of August 24, 2012.

As described above, Buckeye used the proceeds of the Credit Facility to repay its outstanding balance under the Prior BPL Credit Facility and terminated the Prior BPL Credit Facility on September 26, 2011. As a result of the termination of the Prior BPL Credit Facility, we expensed $0.3 million of unamortized deferred financing costs, which is reflected in Interest and debt expense in our consolidated statement of operations. As of December 31, 2010, Buckeye had an outstanding balance of $98.0 million under the Prior BPL Credit Facility.

BES Credit Facility

The BES Credit Facility 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 its 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. BES incurred $3.3 million of debt issuance costs related to the amendment, which was being amortized into interest expense over the term of the credit agreement.

As described above, BES used the proceeds of the Credit Facility to repay its outstanding balance under the BES Credit Facility and terminated the BES Credit Facility on September 26, 2011. As a result of the termination of the BES Credit Facility, we expensed $3.0 million, of unamortized deferred financing costs, which is reflected in Interest and debt expense in our consolidated statement of operations. As of December 31, 2010, BES had an outstanding balance of $284.3 million, which was classified as a current liability in our consolidated balance sheets. The BES outstanding balance was classified as current liabilities in our consolidated balance sheets as related funds were used to finance current working capital needs.

13. OTHER NON-CURRENT LIABILITIES

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

	December 31,	
	2011	2010
Accrued employee benefit liabilities	$ 51,173	$ 49,170
Accrued environmental liabilities (1)	45,857	20,346
Deferred consideration	17,264	16,415
Deferred rent	17,515	13,393
Uncertain tax position liability (see Note 2)	17,720	17,720
Unfavorable storage contracts (2)	39,145	—
Other	7,281	10,999
Total other non-current liabilities	$ 195,955	$ 128,043

(1) Amount for 2011 includes environmental liabilities acquired in connection with the BORCO and terminal and pipeline acquisitions. See Note 3 for further information on the respective acquisitions.

(2) At December 31, 2011, the amount is net of approximately $7.6 million of recognized revenue. Revenue to be recognized related to these unfavorable storage contracts is expected to be approximately $11.0 million for each of 2012 and 2013, $11.1 million for each of 2014 and 2015 and $6.0 million for 2016. See Note 3 for a discussion of the unfavorable storage contracts acquired in connection with the BORCO acquisition.

14. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Accumulated other comprehensive income (loss) ("AOCI") consists of the following at the dates indicated (in thousands):

	December 31, 2011	December 31, 2010
Adjustments to funded status of benefit plans	$ (20,457)	$ (17,614)
Unrealized losses on derivative instruments	(107,735)	(3,645)
Gain on settlement of treasury lock, net of amortization	451	—
Total accumulated other comprehensive loss	$ (127,741)	$ (21,259)

15. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

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 forecasted 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.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategies for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items. A discussion of our derivative activities by risk category follows.

Interest Rate Derivatives

We utilize forward-starting interest rate swaps to manage interest rate risk related to forecasted interest payments on anticipated debt issuances. This strategy is a component in controlling our cost of capital associated with such borrowings by mitigating the adverse effect of a change in the capital market. 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 change in fair value of the swap instruments is positive and the counterparty may 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 aligning the swap instrument with the existing underlying 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, 2011 and 2010, unrealized losses of $104.8 million and $13.9 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.

On January 13, 2011, we issued the 4.875% Notes in an underwritten public offering. See Note 12 for further discussion. 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.

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

Commodity Derivatives

Our Energy Services segment primarily uses exchange-traded refined petroleum product futures contracts to manage the risk of market price volatility on its refined petroleum product inventories and its physical commodity fixed-price purchase and sales contracts. The derivative contracts used to hedge refined petroleum product 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 fixed-price contracts. Therefore, our fixed-price contracts and the related futures contracts used to offset the changes in fair value of the fixed-price 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 Pipelines & Terminals segment bought natural gas futures contracts in March 2009 with terms that coincide with the remaining term of an ongoing natural gas supply contract that expired August 2011. The natural gas futures contracts were designated as cash flow hedges at inception and the change in fair value was recorded in OCI. As the forecasted event occurred and was recognized in earnings, the change in fair value was reclassed from AOCI to earnings. As of December 31, 2011, there were no designated cash flow hedges of our natural gas supply contracts and the amount that had been recorded in AOCI was reclassed to earnings.

The following table summarizes our commodity derivative instruments outstanding at December 31, 2011 (amounts in thousands of gallons, except as noted):

	Volume (1)		
Derivative Purpose	**Current**	**Long-Term (2)**	**Accounting Treatment**
Derivatives Not designated as hedging instruments:			
Physical fixed price derivative contracts for refined products	27,744	—	Mark-to-market
Physical index derivative contracts	155,054	—	Mark-to-market
Futures contracts for refined products	30,324	—	Mark-to-market
Derivatives designated as hedging instruments:			
Futures contracts for refined products	95,277	—	Fair Value Hedge

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

(2) At December 31, 2011, we did not have any derivatives with a contract month exceeding December 31, 2012.

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

	December 31, 2011				
	Derivatives Not Designated as Hedging Instruments	Derivatives Designated as Hedging Instruments	Derivative Net Carrying Value	Netting Balance Sheet Adjustment	Total
Physical fixed price derivative contracts	$ 5,351	$ —	$ 5,351	$ (59)	$ 5,292
Physical index derivative contracts	853		853	(19)	834
Futures contracts for refined products	3,594	2,664	6,258	(5,628)	630
Total current derivative assets	9,798	2,664	12,462	(5,706)	6,756
Physical derivative contracts	(1,304)	—	(1,304)	59	(1,245)
Physical index derivative contracts	(633)	—	(633)	19	(614)
Futures contracts for refined products	(3,154)	(2,474)	(5,628)	5,628	—
Total current derivative liabilities	(5,091)	(2,474)	(7,565)	5,706	(1,859)
Interest rate derivatives	—	(101,911)	(101,911)	—	(101,911)
Total non-current derivative liabilities	—	(101,911)	(101,911)	—	(101,911)
Net derivative assets/(liabilities)	$ 4,707	$ (101,721)	$ (97,014)	$ —	$ (97,014)

	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 assets/(liabilities)	$ 13,170	$ (24,929)	$ (11,759)	$ —	$ (11,759)

Our hedged inventory portfolio extends to the second quarter of 2012. The majority of the unrealized gain of $0.2 million at December 31, 2011 for inventory hedges represented by futures contracts will be realized by the second quarter of 2012 as the related inventory is sold. At December 31, 2011, open refined petroleum product derivative contracts (represented by the fixed-price sales contracts and futures contracts for fixed-price sales contracts noted above) varied in duration in the overall portfolio, but did not extend beyond December 2012. In addition, at December 31, 2011, we had refined petroleum product inventories that we intend to use to satisfy a portion of the physical derivative contracts.

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

	December 31, 2011	December 31, 2010
Derivative assets	$ 6,756	$ 1,634
Other non-current assets	—	3,892
Derivative liabilities	(1,859)	(17,285)
Other non-current liabilities	(101,911)	—
Total	$ (97,014)	$ (11,759)

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

	Location	Gain (Loss) Recognized in Income on Derivatives for the Year Ended December 31, 2011	2010
Derivatives Not designated as hedging instruments:			
Physical fixed price derivative contracts	Product sales	$ 5,141	$ 3,032
Physical index derivative contracts	Product sales	123	—
Physical fixed price derivative contracts	Cost of product sales and natural gas storage services	5,968	—
Physical index derivative contracts	Cost of product sales and natural gas storage services	98	—
Futures contracts for refined products	Cost of product sales and natural gas storage services	7,103	22,073
Derivatives designated as fair value hedging instruments:			
Futures contracts for refined products	Cost of product sales and natural gas storage services	$ (47,681)	$ (61,235)
Physical Inventory—hedged items	Cost of product sales and natural gas storage services	37,986	55,405
Ineffectiveness excluding the time value component on fair value hedging instruments:			
Fair Value hedge ineffectiveness (excluding time value)	Cost of product sales and natural gas storage services	$ (500)	$ 9,746
Time value excluded from hedge assessment	Cost of product sales and natural gas storage services	(9,195)	(15,576)
Net loss in income		$ (9,695)	$ (5,830)

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):

	Location	Gain (Loss) Reclassified From AOCI to Income for the Year Ended December 31, 2011	2010
Derivatives designated as cash flow hedging instruments:			
Futures contracts for natural gas	Cost of product sales and natural gas storage services	$ (250)	$ (428)
Interest rate derivatives	Interest and debt expense	(920)	(964)

	Change in Value Recognized in OCI on Derivatives for the Year Ended December 31, 2011	2010
Derivatives designated as cash flow hedging instruments:		
Futures contracts for natural gas	$ (46)	$ (929)
Interest rate derivatives	(104,763)	(13,856)

16. FAIR VALUE MEASUREMENTS

We categorize our financial assets and liabilities using the three-tier hierarchy as follows:

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, 2011 and 2010, and the basis for that measurement, by level within the fair value hierarchy (in thousands):

	December 31, 2011		2010	
	Level 1	Level 2	Level 1	Level 2
Financial assets:				
Physical fixed price derivative contracts	$ —	$ 5,292	$ —	$ 1,522
Physical index derivative contracts	—	834	—	—
Futures contracts for refined products	630	—	112	—
Interest rate derivatives	—	—	—	3,892
Financial liabilities:				
Physical fixed price derivative contracts	—	(1,245)	—	(3,900)
Physical index derivative contracts	—	(614)	—	—
Futures contracts for refined products	—	—	(12,635)	—
Futures contracts for natural gas	—	—	(206)	—
Interest rate derivatives	—	(101,911)	—	(544)
Fair value	$ 630	$ (97,644)	$ (12,729)	$ 970

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

The values of the Level 2 interest rate derivatives were determined using expected cash flow models, which incorporated market inputs including the implied 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 fixed price derivative contracts assets of $5.3 million and $1.5 million as of December 31, 2011 and 2010, respectively, are net of CVA of ($0.1) million for both periods, 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. During the year ended December 31, 2011, we recorded a non-cash goodwill impairment charge of $169.6 million based on Level 3 inputs. See Note 9 for a discussion of our valuation methodology relating to the goodwill impairment test. During the year ended December 31, 2009, we recorded a non-cash asset impairment charge of $59.7 million 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 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 VERP (defined in Note 23) and involuntary reduction in workforce (see Note 23), we recognized a settlement in the RIGP of approximately $14.0 million for the year ended December 31, 2009 as a 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.

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		Retiree Medical Plan	
	Year Ended December 31,		Year Ended December 31,	
	2011	2010	2011	2010
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 17,959	$ 19,103	$ 39,835	$ 35,449
Service cost	284	263	303	295
Interest cost	827	906	1,927	1,982
Plan participants' contributions	—	—	486	397
Actuarial loss (gain)	3,689	1,281	(781)	4,490
Settlements	(1,375)	—	—	—
Benefit payments	(93)	(3,594)	(2,773)	(2,778)
Benefit obligation at end of year	$ 21,291	$ 17,959	$ 38,997	$ 39,835
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 4,807	$ 5,427	$ —	$ —
Actual return on plan assets	890	244	—	—
Plan participants' contributions	—	—	486	397
Employer contribution	2,389	2,730	2,287	2,381
Settlements	(1,375)	—	—	—
Benefits paid	(93)	(3,594)	(2,773)	(2,778)
Fair value of plan assets at end of year	$ 6,618	$ 4,807	$ —	$ —
Funded status at end of year	$ (14,673)	$ (13,152)	$ (38,997)	$ (39,835)

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

	RIGP		Retiree Medical Plan	
	December 31,		December 31,	
	2011	2010	2011	2010
Liabilities:				
Accrued employee benefit liabilities—current	$ —	$ —	$ 3,071	$ 3,817
Accrued employee benefit liabilities—noncurrent	$ 14,673	$ 13,152	$ 35,926	$ 36,018
AOCI:				
Net actuarial loss	$ 11,160	$ 9,829	$ 13,078	$ 15,103
Prior service credit	—	—	(4,353)	(7,318)
Total	$ 11,160	$ 9,829	$ 8,725	$ 7,785

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,	
	2011	2010
Projected benefit obligation	$ 21,291	$ 17,959
Accumulated benefit obligation	14,687	11,119
Fair value of plan assets	6,618	4,807

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

	RIGP			Retiree Medical Plan		
	Year Ended December 31,			Year Ended December 31,		
	2011	2010	2009	2011	2010	2009
Weighted average expense assumptions:						
Discount rate	4.7%	5.3%	5.5%	5.1%	5.8%	5.8%
Expected return on plan assets	6.0%	6.0%	7.5%	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		Retiree Medical Plan	
	December 31,		December 31,	
	2011	2010	2011	2010
Weighted average balance sheet assumptions:				
Discount rate	4.2%	4.7%	4.6%	5.1%
Expected return on plan assets	5.8%	6.0%	N/A	N/A

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, 2011 in the Retiree Medical Plan was 8.0% for 2012, decreasing to 4.5% by 2021, remaining at that level 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 2011 results:

	1% Increase	1% (Decrease)
Effect on total service cost and interest cost components	$ 101	$ (90)
Effect on postretirement benefit obligation	1,449	(1,301)

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			Retiree Medical Plan		
	Year Ended December 31,			Year Ended December 31,		
	2011	2010	2009	2011	2010	2009
Components of net periodic benefit cost:						
Service cost	$ 284	$ 263	$ 495	$ 303	$ 294	$ 339
Interest cost	827	907	1,182	1,927	1,982	1,941
Expected return on plan assets	(347)	(344)	(570)	—	—	—
Recognized gain due to curtailments	—	—	—	—	—	(749)
Amortization of prior service cost benefit.	—	(46)	(485)	(2,964)	(2,964)	(3,240)
Actuarial loss due to settlements	694	—	7,280	—	—	—
Amortization of unrecognized losses	1,121	967	1,069	1,244	894	1,016
Net periodic benefit costs	$ 2,579	$ 1,747	$ 8,971	$ 510	$ 206	$ (693)
Other changes in plan assets and benefit obligations recognized in OCI:						
Net actuarial loss (gain)	$ 3,287	$ 1,380	$ 5,328	$ (781)	$ 4,490	$ 875
Amortization of net actuarial gain	(1,815)	(967)	(1,069)	(1,244)	(894)	(1,016)
Actuarial loss due to settlements	—	—	(7,280)	—	—	—
Amortization of prior service cost	—	46	485	2,964	2,964	3,240
Total recognized in OCI	$ 1,472	$ 459	$ (2,536)	$ 939	$ 6,560	$ 3,099
Total recognized in net period benefit cost and OCI	$ 4,051	$ 2,206	$ 6,435	$ 1,449	$ 6,766	$ 2,406

During the year ending December 31, 2012, 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	$ 1,389	$ 1,036
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
2012	$ 2,413	$ 3,141
2013	1,575	3,217
2014	1,730	3,229
2015	2,070	3,270
2016	2,264	3,236
Thereafter	10,861	13,937

We expect to contribute approximately $6.1 million to our benefit plans in 2012. 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,			
	2011		2010	
	Level 1	Level 3	Level 1	Level 3
Mutual fund—equity securities (1)	$ 880	$ —	$ 609	$ —
Mutual fund—money market	1,736	—	760	—
Coal lease (2)	—	3,468	—	3,438
Fair value of plan assets	$ 2,616	$ 3,468	$ 1,369	$ 3,438

(1) This mutual fund generally seeks long-term growth of capital and income and invests in a portfolio consisting of 100% in equities.

(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.

The following table summarizes the activity in our Level 3 pension assets for the periods indicated (in thousands):

	Year Ended December 31,	
	2011	2010
Beginning balance, January 1	$ 3,438	$ 3,564
Lease payments received	296	392
Unrealized gain (loss)	30	(126)
Transfers out of Level 3	(296)	(392)
Ending balance, December 31	$ 3,468	$ 3,438

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 Plans

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 located in the continental United States, except those covered by certain labor contracts. The eligible employees located in the Bahamas are covered by a separate retirement and savings plan.

The Retirement and Savings Plan offered to employees in the continental United States 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, 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. Total costs of the Retirement and Savings Plan were approximately $8.5 million, $6.0 million and $7.1 million during the years ended December 31, 2011, 2010 and 2009, respectively.

The retirement and savings plan offered to employees located in the Bahamas consist of a matching contribution into the employee's separate account for up to 12% of each eligible employee's covered salary. The contribution is determined according to the period of employment, employees' contribution to the plan and the gross salary. Total costs of the BORCO's retirement and savings plan were approximately $0.7 million during the year ended December 31, 2011.

Additionally, pursuant to the BORCO acquisition in January 2011, we inherited BORCO's defined contribution plan under which we pay fixed contributions to an individual account for each participant. The pension contribution for permanent employees is between 3% and 6% of regular earnings, depending on years of service and classification of employee. Total costs of BORCO's defined contribution plan was approximately $0.6 million during the year ended December 31, 2011.

Services Company also participates in a multi-employer retirement income plan that provides benefits to employees covered by certain labor contracts. We do not administer these plans and contribute to them in accordance with the provisions of negotiated labor contracts. Pension expense for the plan was $0.3 million, $0.3 million and $0.3 million during the years ended December 31, 2011, 2010 and 2009, 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. We do not administer these plans and contribute to them in accordance with the provisions of negotiated labor contracts. The cost of providing these benefits was $0.2 million, $0.3 million and $0.2 million during the years ended December 31, 2011, 2010 and 2009, respectively.

18. UNIT-BASED COMPENSATION PLANS

BGH GP Holding LLC ("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 $0 million, $1.2 million and $1.3 million for the years ended December 31, 2011, 2010 and 2009, 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 $9.2 million, $7.7 million and $3.1 million for the years ended December 31, 2011, 2010 and 2009, 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, 2011 and 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 partners' capital, 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 $0 million, $1.2 million and $1.3 million for the years ended December 31, 2011, 2010 and 2009, 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%.

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. There were no Value A, Value B or Operating units granted during the year ended December 31, 2011 or 2010. On December 31, 2011 and 2010, 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.

On January 27, 2011, BGH GP established and granted new override units in BGH GP to a member of senior management, which consisted of Value N-1 and Value N-2 Units. The Value N-1 Units will participate in distributions by BGH GP based on the occurrence of an exit event and an investment return of 2.0 times the original investment up to aggregate distributions of $3.0 million. The Value N-2 Units will participate in distributions by BGH GP based on the occurrence of an exit event and an investment return of 2.5 times the original investment or on a pro-rata basis on an investment return ranging from 2.0 to 2.5 times the original investment up to aggregate distributions of $5.0 million.

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

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

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.

The cumulative grant date fair values of the Value-B, Value N-1 and Value N-2 Units that remained unvested as of December 31, 2011 are $2.2 million, $0.9 million and $1.1 million, respectively. The vesting of the override units that remain unvested is contingent on a performance condition, namely the completion of the exit event, and a market condition, primarily relating to the receipt of an investment return at a specified multiple and internal rate of return, where applicable. Accordingly, no compensation expense for these override units will be recorded until, and if, an exit event and other requirements occur.

At the 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 period:

	Year Ended December 31,		
	2011 (1)	2010 (2)	2009 (3)
Current equity value (in millions)	$ 410.70	$ —	$ 439.06
Expected life in years	1.0	—	3.4
Risk-free interest rate	0.3%	—	1.8%
Volatility	0.25	—	0.45

(1) The assumptions were used for grants of the Value N-1 and N-2 Units during the period.
(2) There were no override units granted during the year ended December 31, 2010.
(3) The assumptions were used for grants of the Value A, Value B, and Operating Units during the period.

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, 2011, awards representing a total of 877,969 additional LP Units could be issued under the LTIP.

On December 16, 2009, the Compensation Committee approved the terms of the Buckeye Partners, L.P. Unit Deferral and Incentive Plan ("Deferral Plan"). The Compensation Committee is expressly authorized to adopt the Deferral Plan under the terms of the LTIP, which grants the Compensation Committee the authority to establish a program pursuant to which our phantom units may be awarded in lieu of cash compensation at the election of the employee. At December 31, 2011, 2010 and 2009, eligible employees were allowed to defer up to 50% of their 2011, 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 $0.7 million of 2011 compensation awards had been deferred at December 31, 2011 for which phantom units will be granted in 2012. Approximately $1.6 million of 2010 compensation awards had been deferred at December 31, 2010, for which 50,660 phantom units (including matching units) were granted during 2011. These grants are included as granted in the LTIP activity table below.

Awards under the LTIP

During the year ended December 31, 2011, the Compensation Committee granted 112,257 phantom units to employees (including the 50,660 phantom units granted pursuant to the Deferral Plan discussed above), 14,000 phantom units to non-employee directors of Buckeye GP, and 124,927 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 $1.2 million and $0.6 million for the years ended December 31, 2011 and 2010, 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. 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.

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
Granted	251,184	$ 64.88	$ 16,296
Vested	(17,553)	55.53	(975)
Forfeited	(13,227)	57.03	(754)
Unvested at December 31, 2011	585,317	$ 56.75	$ 33,217

(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, 2011, approximately $13.7 million of compensation expense related to the LTIP is expected to be recognized over a weighted average period of approximately 1.2 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 2012, 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, 2011 is based upon options ultimately expected to vest. Forfeitures have been estimated at the time of grant and will be revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates. Forfeitures were estimated based upon historical experience.

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

Following the adoption of the LTIP on March 20, 2009, we ceased making additional grants under the Option Plan. There were no option grants during 2010 or 2011.

The following is a summary of the changes in the options outstanding (all of which are vested) 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
Exercised	(144,800)	47.10		
Outstanding at December 31, 2011	97,000	46.81	4.2	$ 1,666
Exercisable at December 31, 2011	97,000	$ 46.81	4.2	$ 1,666

(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 2011 and the exercise price, multiplied by the number of exercisable, in-the-money options.

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010 and 2009 was $2.5 million, $1.7 million and $0.5 million, respectively. At December 31, 2011, total unrecognized compensation cost related to unvested options was $0 as all options were vested as of November 24, 2011. At December 31, 2011, 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 $0.2 million, $0.4 million and $0.4 million during the years ended December 31, 2011, 2010 and 2009, 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, Services Company had total debt outstanding of $1.5 million consisting of 3.60% Senior Secured Notes due March 28, 2011 payable by the ESOP to a third-party lender, which was repaid on March 28, 2011.

In connection with the March 2011 repayment of the ESOP Notes, the ESOP was frozen with respect to participation and benefits effective March 27, 2011 (the "Freeze Date"). No Company contributions (other than dividend equivalent payments) will be made on behalf of current participants in the Plan on and after the Freeze Date. Even though contributions under the ESOP are no longer being made, each eligible participant's ESOP Account will continue to be credited with its share of any stock dividends or other stock distributions associated with Services Company Stock.

Services Company stock was 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 were allocated shares based upon the ratio of their eligible compensation to total eligible compensation. Eligible compensation generally included base salary, overtime payments and certain bonuses. All Services Company stock has been released to ESOP participants. Total ESOP related costs charged to earnings were $1.2 million, $5.0 million and $2.5 million for the years ended December 31, 2011, 2010 and 2009, 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. Services Company employees provide services to the majority of our operating subsidiaries. Pursuant to a services agreement entered into in December 2004, our operating subsidiaries reimburse Services Company for the costs of the services provided by Services Company. Services Company, which is beneficially owned by the ESOP, owned 1.3 million of our LP Units (approximately 1.5% of our LP Units outstanding) as of December 31, 2011. Distributions received by Services Company from us on such LP Units are distributed to ESOP participants for investment pursuant to the terms of the ESOP. Distributions paid to Services Company totaled $5.6 million, $5.9 million and $7.2 million for the years ended December 31, 2011, 2010 and 2009, 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.

On August 18, 2010, we and our general partner entered into the Merger Agreement with BGH, its general partner and Merger Sub, our subsidiary. 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. 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. As the Merger was consummated in November 2010, no incentive distributions were paid during the year ended December 31, 2011. Incentive distribution payments totaled $51.0 million and $45.7 million during the years ended December 31, 2010 and 2009, respectively.

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. Prior to the Merger, 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.

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

Equity Offering

On April 15, 2011, we issued 5,520,000 LP Units, which included 720,000 LP Units issued as part of the overallotment option, in an underwritten public offering at a public offering price of $59.41 per LP Unit. Total proceeds from the offering, including the overallotment option and after the underwriters' discount of $1.99 per LP Unit and offering expenses, were approximately $316.6 million, and were used to reduce amounts outstanding under our Prior BPL Credit Facility.

On January 18 and 19, 2011, we issued 5,794,725 LP Units and 1,314,870 Class B Units to institutional investors for aggregate consideration of approximately $425.0 million to fund a portion of the BORCO acquisition. On January 18, 2011, we issued 2,483,444 LP Units and 4,382,889 Class B Units to First Reserve as $400.0 million of consideration to fund a portion of the BORCO acquisition. On February 16, 2011, we issued 620,861 LP Units and 1,095,722 Class B Units to Vopak as $100.0 million of consideration to fund a portion of the BORCO acquisition. Equity issuance costs incurred on these transactions were approximately $4.6 million. The remaining purchase price was funded with cash on hand at closing and borrowings under our Prior BPL Credit Facility. See Note 3 for further information on the BORCO acquisition.

Summary of Changes in Outstanding Units

The following is a summary of changes in Buckeyes' and BGH's outstanding units for the periods indicated (in thousands):

	General Partner	Limited Partners	Management Units	Class B Units	Total (1)
Units outstanding on January 1, 2009	3	27,767	530	—	28,300
Conversion of management units to common units	—	4	(4)	—	—
Units outstanding at December 31, 2009	3	27,771	526	—	28,300
Cancellation of BGH units in connection with Merger (2)	(3)	(27,771)	(526)	—	(28,300)
Buckeye LP Units issued to BGH unitholders (2)	—	19,951	—	—	19,951
Buckeye LP Units outstanding on date of Merger	—	51,557	—	—	51,557
Cancellation of LP Units in connection with Merger (3)	—	(80)	—	—	(80)
LP Units issued pursuant to the Option Plan	—	8	—	—	8
Units outstanding at December 31, 2010	—	71,436	—	—	71,436
LP Units issued pursuant to the Option Plan	—	97	—	—	97
LP Units issued pursuant to the LTIP	—	16	—	—	16
Issuance of units to First Reserve and Vopak as consideration for BORCO acquisition	—	3,104	—	5,479	8,583
Issuance of units to institutional investors (4)	—	5,795	—	1,315	7,110
Issuance of units in underwritten public offering	—	5,520	—	—	5,520
Issuance of Class B Units in lieu of quarterly cash distribution	—	—	—	511	511
Units outstanding at December 31, 2011	—	85,968	—	7,305	93,273

(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.

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

Cash Distributions

We generally make quarterly cash distributions to unitholders of substantially all of our available cash, generally defined in our partnership agreement as consolidated cash receipts less consolidated cash expenditures and such retentions for working capital, anticipated cash expenditures and contingencies as our general partner deems appropriate. Cash distributions paid to unitholders of Buckeye for the periods indicated 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 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
February 21, 2011	February 28, 2011	$ 0.9875	$ 79,603	$ —	$ 79,603
May 16, 2011	May 31, 2011	1.0000	86,153	—	86,153
August 15, 2011	August 31, 2011	1.0125	87,236	—	87,236
November 14, 2011	November 30, 2011	1.0250	88,377	—	88,377
Total			$ 341,369	$ —	$ 341,369

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

Cash distributions paid to unitholders of BGH for the periods indicated were as follows (in thousands, except per unit amounts):

Record Date	Payment Date	Amount Per Unit	Total Cash Distributions
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

In-kind Distributions

In-kind distributions paid to Class B unitholders of Buckeye for the periods indicated were as follows:

Record Date	Payment Date	Units
February 21, 2011	February 28, 2011	122,244
May 16, 2011	May 31, 2011	127,046
August 15, 2011	August 31, 2011	133,068
November 14, 2011	November 30, 2011	129,041
Total		511,399

On February 10, 2012, we announced a quarterly distribution of $1.0375 per LP Unit that will be paid on February 29, 2012, to unitholders of record on February 21, 2012. Total cash distributed to LP Unitholders on February 29, 2012 will total approximately $89.5 million. We also expect to issue approximately 141,120 Class B Units in lieu of cash distributions on February 29, 2012, to Class B unitholders of record on February 21, 2012.

22. EARNINGS PER UNIT

Basic and diluted earnings per unit (includes LP Units and Class B Units in 2011) 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 Agreement, BGH's unitholders received a total of approximately 20.0 million of Buckeye's LP Units in the aggregate in exchange for all outstanding BGH common units and management units. As a result, the number of Buckeye's LP Units outstanding increased from 51.6 million to 71.4 million. 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 units outstanding used in computing the basic and diluted earnings per unit for the periods indicated (in thousands, except per unit amounts):

	Year Ended December 31,		
	2011	2010	2009
Net income attributable to Buckeye Partners, L.P.	$ 108,501	$ 43,080	$ 49,594
Basic:			
Weighted average units outstanding	90,423	25,627	19,578
Weighted average management units outstanding	—	389	374
Weighted average units outstanding—basic	90,423	26,016	19,952
Earnings per unit—basic	$ 1.20	$ 1.66	$ 2.49
Diluted:			
Weighted average units outstanding—basic	90,423	26,016	19,952
Dilutive effect of LP Unit options and LTIP awards granted	349	70	—
Weighted average units outstanding—diluted	90,772	26,086	19,952
Earnings per unit—diluted	$ 1.20	$ 1.65	$ 2.49

23. 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):

Pipelines & Terminals	$ 28,862
Natural Gas Storage	495
Energy Services	1,207
Development & Logistics	1,493
Total reorganization expenses	$ 32,057

24. RELOCATION

On August 16, 2011, we announced our plan to relocate certain corporate and operational related support functions from our Breinigsville, Pennsylvania office to our corporate headquarters located in Houston, Texas. Pursuant to the terms of the plan, approximately 50 employees have been or will be affected as a result of this relocation activity and have or will receive severance benefits, including medical and dental coverage, outplacement services and counselling. Additionally, certain employees will receive a one-time retention payment. The receipt of the severance and retention payments is contingent upon each employee working until their termination date. The severance and retention bonuses are accounted for in accordance with Accounting Standards Codification ("ASC") 712, *Compensation—Nonretirement Postemployment Benefits* and ASC 420, *Exit or Disposal Cost Obligations*, respectively.

As of December 31, 2011, we accrued $1.0 million for the severance and retention payments earned during the period for which the liability and expense will be recognized ratably over the future service period. Additionally, we recorded a relocation expense of $0.6 million related to relocation costs of transition staffing, travel, and other relocation costs. These expenses were recorded in general and administrative expenses in our consolidated statement of operations for the period ending December 31, 2011. These relocation costs will be allocated to each business segment, except for the International Operations segment. We expect to incur additional expenses of approximately $6.0 million in the aggregate through the completion of the relocation in July 2013.

25. BUSINESS SEGMENTS

We operate and report in five business segments: i) Pipelines & Terminals; ii) International Operations; iii) Natural Gas Storage; iv) Energy Services; and v) Development & Logistics. Effective January 1, 2011, we realigned our business segments. We combined our former Pipeline Operations and Terminalling & Storage segments into one segment, the Pipelines & Terminals segment, and moved our terminal in Yabucoa, Puerto Rico, previously included as part of the Terminalling & Storage segment, and the BORCO facility to a new International Operations segment. We have adjusted our prior period segment information to conform to the current presentation.

Pipelines & Terminals

The Pipelines & Terminals segment receives refined petroleum products from refineries, connecting pipelines, and bulk and marine terminals and transports those products to other locations for a fee and provides bulk storage and terminal throughput services in the continental United States. This segment owns and operates approximately 6,100 miles of pipeline systems in 16 states. The segment has approximately 100 refined petroleum products terminals, which includes five terminals owned by the Energy Services segment, in 21 states with aggregate storage capacity of approximately 37.4 million barrels.

International Operations

The International Operations segment provides marine bulk storage and marine terminal throughput services. The segment has two refined petroleum product terminals, one in Puerto Rico and one on The Grand Bahama Island, in the Bahamas, with an aggregate storage capacity of 26.1 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 30 Bcf of working natural gas storage capacity and is connected to Pacific Gas and Electric's intrastate natural 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 in Pennsylvania 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 2,800 miles of third-party pipeline, 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 Pipeline, 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. 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 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) non-cash impairment expense related to the Buckeye NGL Pipeline that we sold in January 2010, (iv) organizational restructuring expense, (v) non-cash BGH GP equity plan modification expense, (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 and (vii) non-cash goodwill impairment expense associated with the Natural Gas Storage segment; less: (i) amortization of unfavorable storage contracts acquired in connection with the BORCO acquisition and (ii) gain on the sale of our equity investment in WT LPG.

The EBITDA and Adjusted EBITDA data presented may not be comparable to similarly titled measures at other companies because EBITDA and Adjusted EBITDA exclude some items that affect net income 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.

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 continental United States, except for our terminals located in Puerto Rico and The Bahamas.

For the years ended December 31, 2011, 2010 and 2009, no customer contributed 10% or more of consolidated revenue.

The following tables show our measurement of Adjusted EBITDA, a reconciliation of Adjusted EBITDA to net income (loss) attributable to our unitholders and financial information about each segment for the periods indicated (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Adjusted EBITDA:			
Pipelines & Terminals	$ 361,018	$ 346,447	$ 302,164
International Operations	112,996	(4,655)	—
Natural Gas Storage	4,204	29,794	41,950
Energy Services	1,797	5,861	19,335
Development & Logistics	7,932	5,193	6,718
Total Adjusted EBITDA	487,947	382,640	370,167
Interest and debt expense	(119,561)	(89,169)	(75,147)
Income tax benefit	192	919	343
Depreciation and amortization	(119,534)	(59,590)	(54,699)
Net income attributable to noncontrolling interests(1) affected by Merger (for periods prior to Merger)	—	(157,467)	(90,381)
Non-cash deferred lease expense	(4,122)	(4,235)	(4,500)
Non-cash unit-based compensation expense	(9,150)	(8,960)	(4,408)
Equity plan modification expense	—	(21,058)	—
Asset impairment expense	—	—	(59,724)
Goodwill impairment expense	(169,560)	—	—
Gain on sale of equity investment	34,727	—	—
Amortization of unfavorable storage contracts	7,562	—	—
Reorganization expense	—	—	(32,057)
Net income attributable to Buckeye Partners, L.P.	108,501	43,080	49,594
Add: net income attributable to noncontrolling interests	6,163	157,928	92,043
Net income	$ 114,664	$ 201,008	$ 141,637

(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 period for comparability purposes.

	Year Ended December 31,		
	2011	2010	2009
Revenue:			
Pipelines & Terminals	$ 631,289	$ 574,990	$ 529,243
International Operations (1)	193,960	936	—
Natural Gas Storage	65,990	95,337	99,163
Energy Services	3,888,961	2,481,566	1,125,013
Development & Logistics	43,068	37,696	34,136
Intersegment	(63,658)	(39,257)	(17,183)
Total revenue	$ 4,759,610	$ 3,151,268	$ 1,770,372
Operating income (loss):			
Pipelines & Terminals	$ 290,573	$ 266,184	$ 155,041
International Operations	72,067	(4,656)	—
Natural Gas Storage	(177,163)	16,069	30,574
Energy Services	(4,462)	(1,367)	13,086
Development & Logistics	7,859	3,271	5,099
Total operating income	$ 188,874	$ 279,501	$ 203,800
Depreciation and amortization:			
Pipelines & Terminals	$ 55,469	$ 46,320	$ 42,791
International Operations	50,011	—	—
Natural Gas Storage	7,136	6,594	5,971
Energy Services	5,261	4,933	4,204
Development & Logistics	1,657	1,743	1,733
Total depreciation and amortization	$ 119,534	$ 59,590	$ 54,699

(1) The International Operations segment's revenue generated in The Bahamas was $177.6 million for the year ended December 31, 2011, which represents 91.6% of the International Operations segment's total revenue for the period.

	Year Ended December 31,		
	2011	2010	2009
Capital additions, net: (1)			
Pipelines & Terminals	$ 103,678	$ 65,527	$ 56,924
International Operations	184,438	—	—
Natural Gas Storage	10,097	8,328	23,033
Energy Services	1,824	2,961	6,236
Development & Logistics	5,287	883	1,116
Total capital additions, net	$ 305,324	$ 77,699	$ 87,309
Total Assets:			
Pipelines & Terminals (2)	$ 2,566,471	$ 2,328,702	$ 2,125,887
International Operations (4)	2,041,209	60,313	—
Natural Gas Storage	365,514	549,876	573,261
Energy Services	518,438	561,382	482,025
Development & Logistics	78,744	73,943	74,476
Consolidating level (3)	—	—	230,922
Total assets	$ 5,570,376	$ 3,574,216	$ 3,486,571

(1) Amounts exclude $14.3 million, $0.4 million and ($3.3) million of non-cash changes in accruals for capital expenditures for the years ended December 31, 2011, 2010 and 2009, respectively (see Note 26).

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

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

(4) The International Operations segment's long-lived assets consist of property, plant and equipment, goodwill, intangible assets and other non-current assets. Total long-lived assets located in or attributable to The Bahamas was $1,954.3 million at December 31, 2011, which was 97.4% of the International Operations segment's total long-lived assets.

26. SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2011	2010	2009
Cash paid for interest (net of capitalized interest)	$ 98,044	$ 83,852	$ 66,264
Cash paid for income taxes	1,147	941	2,316
Capitalized interest	7,583	2,499	3,401
Non-cash investing activities:			
Change in accrued and other current liabilities related to capital expenditures	$ 14,296	$ 421	$ (3,296)
Non-cash financing activities:			
Issuance of units to First Reserve for BORCO acquisition	$ 407,391	$ —	$ —
Issuance of units to Vopak for BORCO acquisition	96,110	—	—
Issuance of Class B Units in lieu of quarterly cash distribution	28,111	—	—

27. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data for the periods indicated is set forth below (in thousands, except per unit amounts). Quarterly results were influenced by seasonal and other factors inherent in our business.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2011					
Revenue	$ 1,252,536	$ 1,077,092	$ 1,116,911	$ 1,313,071	$ 4,759,610
Operating income (loss) (1)	92,563	85,935	(77,305)	87,681	188,874
Net income (loss) (1)	67,813	93,592	(108,200)	61,459	114,664
Net income (loss) attributable to Buckeye Partners, L.P. (1)	66,493	92,021	(109,700)	59,687	108,501
Earnings (loss) per unit—basic and diluted	$ 0.79	$ 1.00	$ (1.18)	$ 0.64	$ 1.20
2010					
Revenue	$ 731,174	$ 667,276	$ 734,857	$ 1,017,961	$ 3,151,268
Operating income (2)	69,491	71,939	79,513	58,558	279,501
Net income (2)	50,642	53,438	60,962	35,966	201,008
Net income attributable to Buckeye Partners, L.P. (2)	11,270	11,507	11,941	8,362	43,080
Earnings per unit—basic (3)	$ 0.56	$ 0.58	$ 0.60	$ 0.19	$ 1.66
Earnings per unit—diluted (3)	$ 0.56	$ 0.58	$ 0.60	$ 0.19	$ 1.65

(1) The second quarter of 2011 includes a gain of $34.1 million, and the fourth quarter of 2011 includes subsequent dividend income of $0.6 million related to the sale of our equity interest in WT LPG (see Note 3). The third quarter of 2011 includes a $169.6 million goodwill impairment expense associated with the Natural Gas Storage segment (see Note 9).

(2) 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).

(3) 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.

28. SUBSEQUENT EVENTS

Perth Amboy Acquisition and Equity Offering

On February 9, 2012, we signed a definitive agreement with Chevron U.S.A Inc. ("Chevron") to acquire a marine terminal facility for liquid petroleum products in New York Harbor (the "Perth Amboy Facility") for $260.0 million in cash. The facility, which sits on approximately 250 acres on the Arthur Kill in Perth Amboy, New Jersey, has over 4 million barrels of tankage, four docks, and significant undeveloped land available for potential expansion. The Perth Amboy Facility has water, pipeline, rail, and truck access, and is located only six miles from our Linden, New Jersey complex. Chevron entered into multi-year storage, blending, and throughput commitments with us concurrent with the acquisition. The Perth Amboy Facility will provide a link between our inland pipelines and terminals and our BORCO facility in The Bahamas, improving service offerings for our customers and providing further support to our planned clean products tankage expansion at the BORCO facility. The operations of the Perth Amboy Facility will be reported in our Pipelines & Terminals segment upon closing, which is expected to close in the latter half of the second quarter of 2012.

Additionally, on February 13, 2012, we issued 4,262,575 LP Units to institutional investors in a registered direct offering for aggregate consideration of approximately $250.0 million at a price of $58.65 per LP Unit, before deducting placement agents fees and estimated offering expenses. We plan to use the net proceeds from this offering to fund indirectly a portion of the Perth Amboy Facility and certain other growth capital expenditures, and, pending such uses, to reduce the indebtedness outstanding under our Credit Facility.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

Item 9A. *Controls and Procedures*

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.

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.

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.

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 2011, 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 2012 Annual Meeting of unitholders (the "2012 Proxy Statement"), which will be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2011, 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 2012 Proxy Statement, which will be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2011, 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.

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 2012 Proxy Statement, which will be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2011, 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 2012 Proxy Statement, which will be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2011, 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 2012 Proxy Statement, which will be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2011, 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 Item 8 of this Report.

(2) Financial Statement Schedules – None.

(3) Exhibits – The following is a list of exhibits filed as part of this Report including those incorporated by reference.

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). †
2.9	Asset Purchase Agreement, by and among BP Products North America Inc., BP West Coast Products LLC, and Buckeye Partners, L.P. dated March 17, 2011 (Incorporated by reference to Exhibit 2.1 of Buckeye Partners, L.P.'s Current Report on Form 8-K filed on March 18, 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., certain operating subsidiaries of Buckeye Partners, L.P. 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 Revolving Credit Agreement, dated as of September 26, 2011, by and among Buckeye Partners, L.P., Buckeye Energy Services, LLC, SunTrust Bank and other lenders party thereto (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P.'s Current Report on Form 8-K filed on September 30, 2011).

10.14 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).

10.15 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).

10.16 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).

10.17 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).

10.18 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).

10.19 Share Purchase Agreement, by and among BP Oil Pipeline Company and Buckeye Partners, L.P., dated March 17, 2011 (Incorporated by reference to Exhibit 2.2 of Buckeye Partners, L.P.'s Current Report on Form 8-K filed on March 18, 2011).

10.20 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.SCHXBRL Taxonomy Extension Schema Document.

**101.CALXBRL Taxonomy Extension Calculation Linkbase Document.

**101.LABXBRL 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.

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 27, 2012 — By: /s/ CLARK SMITH

Clark Smith
Chief Executive Officer, President and Director
(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 27, 2012 — By: /s/ PIETER BAKKER

Pieter Bakker
Director

Dated: February 27, 2012 — By: /s/ C. SCOTT HOBBS

C. Scott Hobbs
Director

Dated: February 27, 2012 — By: /s/ JOSEPH A. LASALA, JR.

Joseph A. LaSala, Jr.
Director

Dated: February 27, 2012 — By: /s/ MARK C. MCKINLEY

Mark C. McKinley
Director

Dated: February 27, 2012 — By: /s/ OLIVER G. "RICK" RICHARD, III

Oliver G. "Rick" Richard, III
Director

Dated: February 27, 2012 — By: /s/ CLARK SMITH

Clark Smith
Chief Executive Officer, President and Director
(Principal Executive Officer)

Dated: February 27, 2012 — By: /s/ FRANK S. SOWINSKI

Frank S. Sowinski
Director

Dated: February 27, 2012	By:	/s/ KEITH E. ST.CLAIR
		Keith E. St.Clair *Executive Vice President and Chief Financial Officer* *(Principal Financial Officer)*
Dated: February 27, 2012	By:	/s/ MARTIN A. WHITE
		Martin A. White *Director*
Dated: February 27, 2012	By:	/s/ FORREST E. WYLIE
		Forrest E. Wylie *Non-Executive Chairman of Board*
Dated: February 27, 2012	By:	/s/ JEFFREY I. BEASON
		Jeffrey I. Beason *Vice President and Controller* *(Principal Accounting Officer)*

Definition and Reconciliation of Non-GAAP Measures

Buckeye's equity-funded merger with Buckeye GP Holdings, L.P. ("BGH") in the fourth quarter of 2010 has been treated as a reverse merger for accounting purposes. As a result, the historical results presented herein for periods prior to the completion of the merger are those of BGH, and the diluted weighted average number of LP units outstanding increase from 20.0 million in the fourth quarter of 2009 to 44.3 million in the fourth quarter of 2010. Additionally, Buckeye incurred a non-cash charge to compensation expense of $21.1 million in the fourth quarter of 2010 as a result of a distribution of LP units owned by BGH GP Holdings, LLC to certain officers of Buckeye, which triggered a revaluation of an equity incentive plan that had been instituted in 2007.

EBITDA, a measure not defined under U.S. generally accepted accounting principles ("GAAP"), is defined by Buckeye as net income attributable to Buckeye's unitholders before interest and debt expense, income taxes, and depreciation and amortization. The EBITDA measure eliminates the significant level of non-cash depreciation and amortization expense that results from the capital-intensive nature of Buckeye's businesses and from intangible assets recognized in business combinations. In addition, EBITDA is unaffected by Buckeye's capital structure due to the elimination of interest and debt expense and income taxes. Adjusted EBITDA, which also is a non-GAAP measure, is defined by Buckeye as EBITDA plus: (i) non-cash deferred lease expense, which is the difference between the estimated annual land lease expense for Buckeye's 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) 2009 non-cash impairment expense related to the Buckeye NGL Pipeline; (iv) 2009 organizational restructuring expense; (v) income attributable to noncontrolling interests related to Buckeye for periods prior to the merger of Buckeye and Buckeye GP Holdings L.P. (the "Merger"); (vi) goodwill impairment expense associated with Lodi Gas Storage, L.L.C. ("Lodi"); and (vii) 2010 non-cash BGH GP Holdings, LLC equity plan modification expense (the "Equity Plan Modification Expense"); less: (i) amortization of unfavorable storage contracts acquired in the BORCO acquisition; and (ii) gain on the sale of our equity investment in West Texas LPG Pipeline Limited Partnership ("WTLPG"). The EBITDA and Adjusted EBITDA data presented may not be directly comparable to similarly titled measures at other companies because EBITDA and Adjusted EBITDA exclude some items that affect net income attributable to Buckeye's unitholders, and these measures may be defined differently by other companies. Management of Buckeye uses Adjusted EBITDA to evaluate the consolidated operating performance and the operating performance of the business segments and to allocate resources and capital to the business segments. In addition, Buckeye's 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.

Distributable cash flow is another measure not defined under GAAP. Distributable cash flow is defined by Buckeye as net income attributable to Buckeye's unitholders plus: (i) depreciation and amortization expense; (ii noncontrolling interests related to Buckeye that were eliminated as a result of the Merger; (iii) deferred lease expense for Buckeye's Natural Gas Storage segment; (iv) unit-based compensation expense; (v) goodwill impairment expense associated with Lodi; (vi) write-off of deferred financing costs; (vii) amortization of deferred financing costs and debt discounts; (viii) Equity Plan Modification Expense; (ix) impairment expense related to Buckeye NGL Pipeline, and (x) reorganization expense (items (i) through (ix) of which are non-cash expense); less: (i) maintenance capital expenditures; (ii) amortization of unfavorable storage contracts acquired in the BORCO acquisition; and (iii) gain on the sale of our equity investment in WTLPG. Buckeye's management believes that distributable cash flow is useful to investors because it removes non-cash items from net income and provides a clearer picture of Buckeye's cash available for distribution to its unitholders.

EBITDA, Adjusted EBITDA, and distributable cash flow should not be considered alternatives to net income, operating income, cash flow from operations, or any other measure of financial performance presented in accordance with GAAP.

Buckeye believes that investors benefit from having access to the same financial measures used by Buckeye's management. Further, Buckeye believes that these measures are useful to investors because they are one of the bases for comparing Buckeye's operating performance with that of other companies with similar operations, although Buckeye's measures may not be directly comparable to similar measures used by other companies.

(in millions except for ratio)	2011	2010	2009	2008	2007
Net Income	$114.7	$201.0	$141.6	$180.6	$152.7
Less: Noncontrolling interests	(6.2)	(157.9)	(92.0)	(154.1)	(129.8)
Net income attributable to Buckeye Partners, L.P.	108.5	43.1	49.6	26.5	22.9
Interest and debt expense	119.6	89.2	75.1	75.4	51.7
Income tax expense (benefit)	(0.2)	(1.0)	(0.3)	0.8	0.8
Depreciation and amortization	119.5	59.6	54.7	50.8	40.2
EBITDA	$347.4	$190.9	$179.1	$153.5	$115.6
Net income attributable to noncontrolling interests affected by merger	---	157.5	90.4	153.5	131.9
Non-cash deferred lease expense	4.1	4.2	4.5	4.6	---
Non-cash unit-based compensation expense	9.1	8.9	4.4	2.0	1.0
Asset impairment expense	---	---	59.7	---	---
Reorganization expense	---	---	32.1	---	---
Equity plan modification expense	---	21.1	---	---	---
Goodwill impairment expense	169.6	---	---	---	---
Gain on sale of equity investment	(34.7)	---	---	---	---
Amortization of unfavorable storage contracts	(7.6)	---	---	---	---
Adjusted EBITDA	**$487.9**	**$382.6**	**$370.2**	**$313.6**	**$248.5**
Less: Interest and debt expense[(1)]	(111.9)	(84.7)	(71.9)	(73.6)	(50.2)
Less: Maintenance capital expenditures	(57.5)	(31.2)	(23.5)	(28.9)	(33.8)
Less: Income taxes and other	0.2	0.9	0.7	1.0	0.2
Distributable cash flow	**$318.7**	**$267.6**	**$275.5**	**$212.1**	**$164.7**
Distributions used for coverage ratio	351.2	259.3	237.7	209.4	173.7
Coverage Ratio	**0.91x**	**1.03x**	**1.16x**	**1.01x**	**0.95x**

(1) In 2011, Buckeye revised its definition of Distributable Cash Flow to exclude amortization of deferred financing costs and debt discounts. Distributable Cash Flow for 2007-2010 has been restated to exclude those amounts for comparison purposes.

	2011	2010	2009
Operating income before special charges:			
Operating income	$188.8	$279.5	$203.8
Asset impairment expense	---	---	59.7
Reorganization expense	---	---	32.1
Equity plan modification expense	---	21.1	---
Goodwill impairment expense	169.6	---	---
Operating income before special charges	$358.4	$300.6	$295.6

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Buckeye GP LLC & Partnership Information

Directors

Forrest E. Wylie
Non-Executive Chairman of the Board

Pieter Bakker

C. Scott Hobbs

Joseph A. LaSala, Jr.

Mark C. McKinley

Oliver G. "Rick" Richard, III

Clark C. Smith
President and Chief Executive Officer

Frank S. Sowinski

Martin A. White

Audit Committee:
C. Scott Hobbs (Chairman)
Frank S. Sowinski
Martin A. White

Compensation Committee:
Oliver G. "Rick" Richard, III (Chairman)
Joseph A. LaSala, Jr.
Mark C. McKinley

Nominating & Corporate Governance Committee:
Frank S. Sowinski (Chairman)
C. Scott Hobbs
Joseph A. LaSala, Jr.

Health, Safety, Security & Environmental Committee:
Martin A. White (Chairman)
Pieter Bakker
Mark C. McKinley
Oliver G. "Rick" Richard, III

Equal Opportunity
Buckeye Partners, L.P. provides equal opportunity in all aspects of employment without regard to race, color, creed, religion, ancestry, national origin, gender, age, disability, veteran, or marital status.

Senior Executives

Clark C. Smith
President and Chief Executive Officer

Keith E. St.Clair
Executive Vice President and Chief Financial Officer

Jeremiah J. Ashcroft, III
Senior Vice President and President of Buckeye Services

Jeffrey I. Beason
Vice President, Controller and Chief Accounting Officer

Mark S. Esselman
Senior Vice President, Global Human Resources

Robert A. Malecky
Senior Vice President and President of Domestic Pipelines & Terminals

Mary F. Morgan
Senior Vice President and President of International Pipelines & Terminals

Khalid A. Muslih
Senior Vice President, Corporate Development & Strategic Planning

William H. Schmidt, Jr.
Vice President and General Counsel

Principal Executive Office
Buckeye Partners, L.P.
One Greenway Plaza, Suite 600
Houston, TX 77046
832-615-8600

Transfer Agent and Registrar
American Stock Transfer & Trust Company, LLC
6201 15th Avenue
Brooklyn, NY 11219
877-724-6457
www.amstock.com

Unitholder Tax Information
PricewaterhouseCoopers, LLP
K-1 Support
P.O. Box 799060
Dallas, TX 75379
800-230-7224

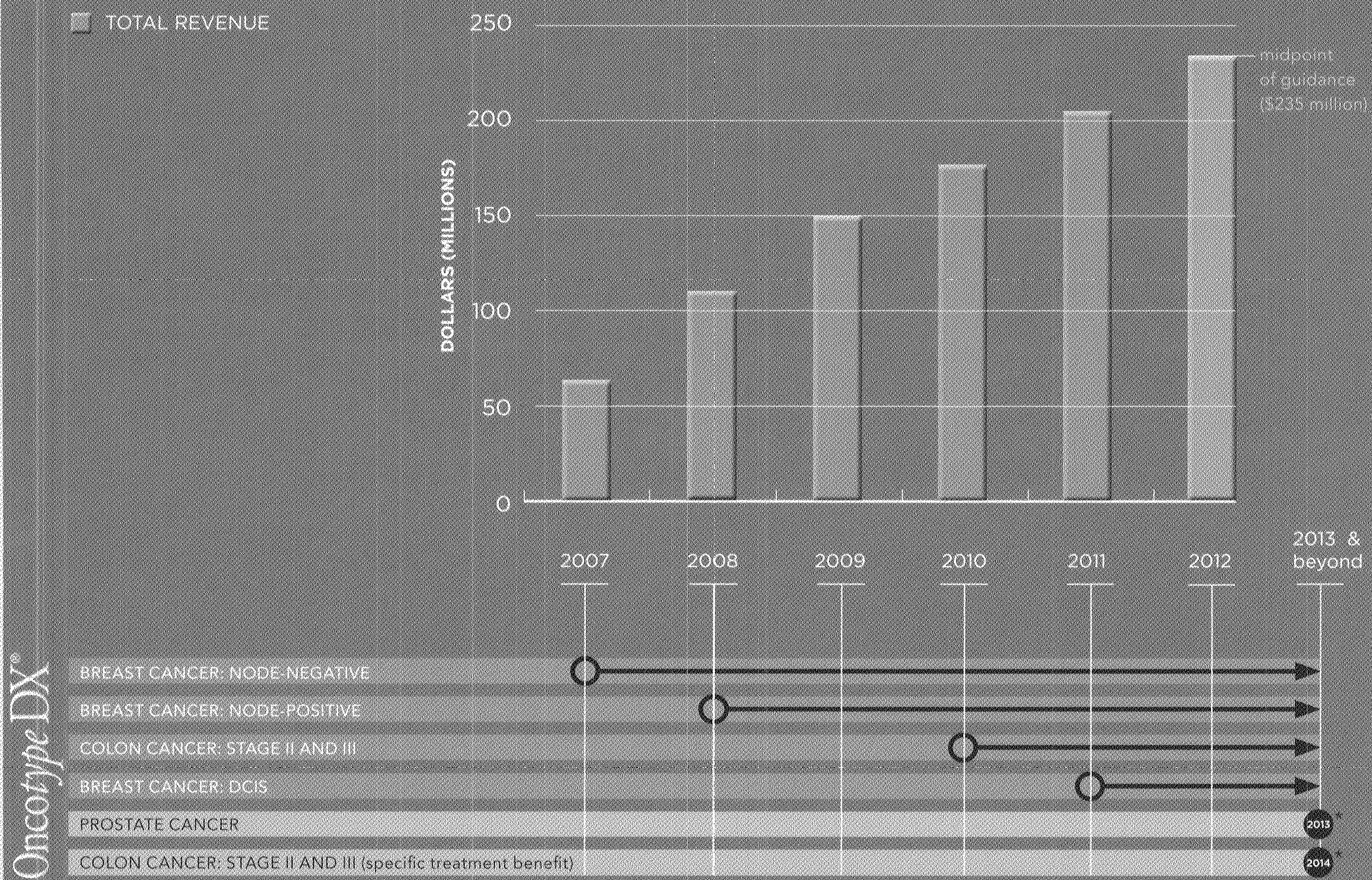
Investor Information
For more information about
Buckeye Partners, L.P. please contact:

Investor Relations
800-422-2825
irelations@buckeye.com
or visit the Investor Center pages
at our website: www.buckeye.com

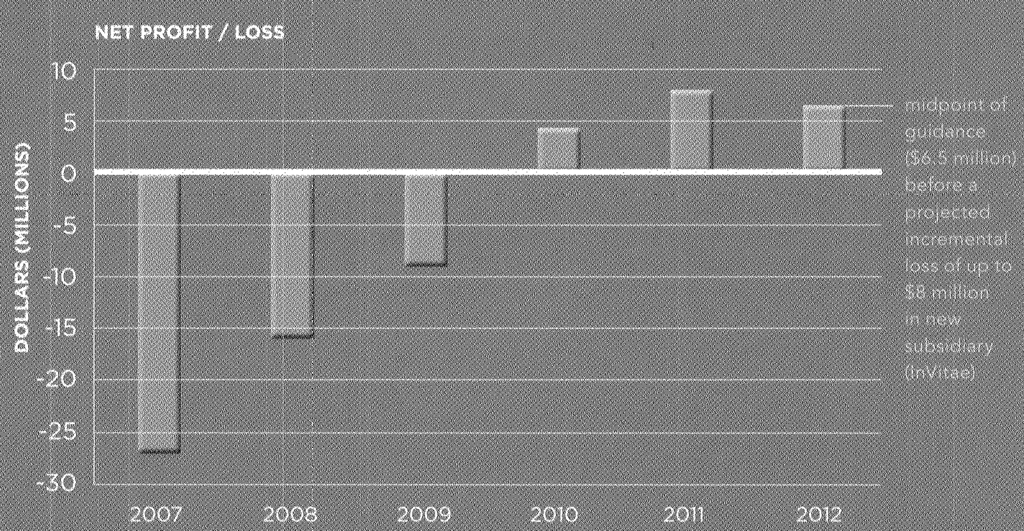
BUCKEYE PARTNERS, L.P.

One Greenway Plaza
Suite 600
Houston, TX 77046
www.buckeye.com

Global Revenue Growth Fueled by Multiple Drivers



Investing Profits in Future Products



* based on projected prostate and colon cancer test launches

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Genomic Health, Inc.
301 Penobscot Drive
Redwood City, CA 94063
1 (866)-ONCOTYPE
genomichealth.com
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