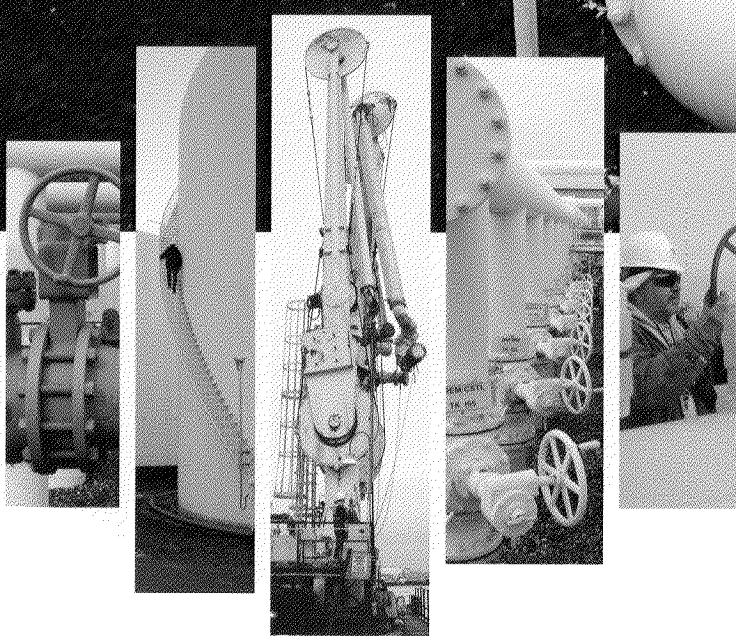
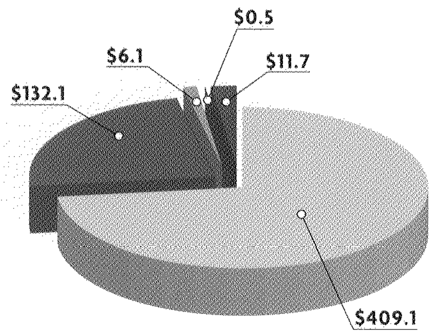


2012 Annual Report

Delivering On Our Growth Strategy

BUCKEYE PARTNERS, L.P.

2012 Adjusted EBITDA[1] Contribution by Segment *(in millions)*



In 2012, Buckeye spent over $270 million on internal growth capital projects, including over $140 million on its BORCO expansion project.

PIPELINES & TERMINALS
Buckeye owns and operates approximately 6,000 miles of pipeline located primarily in the Northeast and Midwest United States. We transport approximately 1.4 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 approximately 42 million barrels.

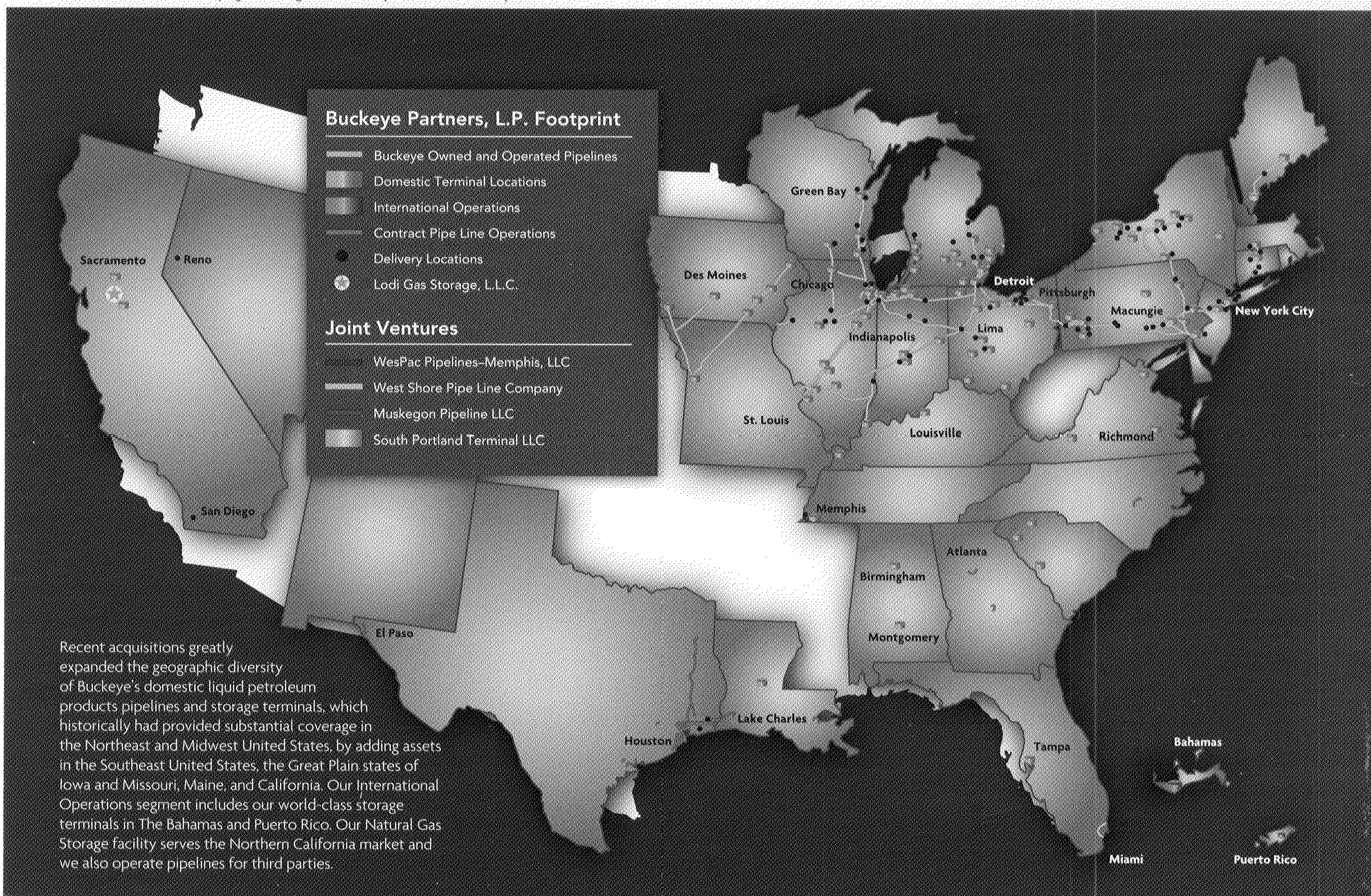
INTERNATIONAL OPERATIONS
Buckeye owns approximately 30 million barrels of storage capacity at two terminal facilities, located in The Bahamas (~ 25 million barrels) and Puerto Rico (~ 5 million barrels), with deep water berthing capability to handle ULCCs and VLCCs in The Bahamas.

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 approximately 1.1 billion gallons of products sold in 2012.

DEVELOPMENT & LOGISTICS
Buckeye Development & Logistics (BDL) operates and maintains 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: Piping and storage tank at Buckeye's Linden, New Jersey terminal.



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 approximately 6,000 miles of pipeline. Buckeye also owns approximately 100 liquid petroleum products terminals with aggregate storage capacity of over 70 million barrels, operates and/or maintains third-party pipelines under agreements with major oil and gas 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. More information concerning Buckeye can be found at www.buckeye.com.

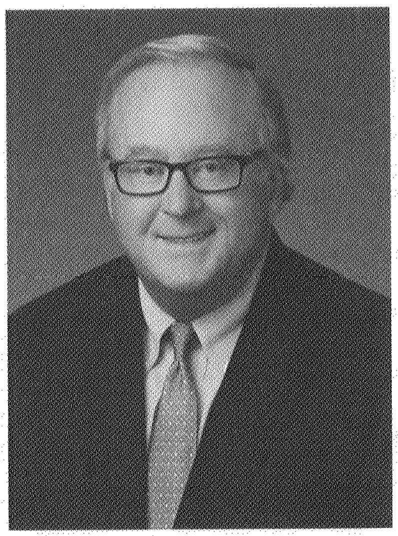
Financial and Operating Highlights

Selected Financial Data	**2012**	2011	2010	2009	2008
(Dollars in millions, except unit, per unit, and operating data)					
Revenue	**$4,357.2**	$4,759.6	$3,151.3	$1,770.4	$1,896.7
Operating Income Before Special Charges[1][2]	**399.2**	358.3	299.7	295.3	247.3
Net Income Attributable to Buckeye Partners, L.P.	**226.4**	108.5	43.1	49.6	26.5
Adjusted EBITDA[2]	**559.5**	487.9	382.6	370.2	313.6
Cash Distributions Per Limited Partner Unit	**4.15**	4.03	3.83	3.63	3.43
Weighted Average Number of LP Units Outstanding—Diluted (in thousands)	**97,635**	90,772	26,086	19,952	19,952
Operating Data					
Pipeline Volumes (Thousands of barrels per day)	**1,385.6**	1,358.1	1,316.4	1,323.1	1,395.4
Average Tariff Rate (Cents per barrel)	**81.5**	76.9	73.6	71.9	67.5
Domestic Terminal Throughput (Thousands of barrels per day)	**897.3**	730.9	562.5	471.9	464.4
Refined Product Sales (Millions of gallons)	**1,106.3**	1,337.8	1,139.1	655.1	435.2

[1] Operating income before special charges excludes the 2012 asset impairment expense, 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 Unitholders:

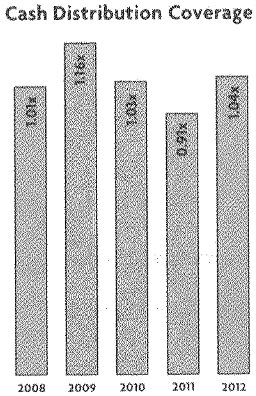


Buckeye was able to achieve record financial results in 2012 while maintaining safe, reliable, and environmentally responsible operations.

I want to begin by thanking our employees and unitholders for being part of one of the great success stories in the petroleum products business. We have been in business and successful for 127 years and have paid quarterly distributions the entire 27 years we have been a publicly traded master limited partnership.

This past year was exciting for Buckeye Partners. We completed the strategic acquisition of a terminal facility in Perth Amboy, New Jersey, which is located on the New York Harbor. This terminal provides waterborne access to the Buckeye system and this access offers security and diversity of product supply to our customers. We initiated an extensive modernization project intended to transform this facility into a highly efficient, multi-product storage, blending, and throughput terminal with crude unit train offloading capability. We also successfully completed the first phases of our storage expansion and facility enhancement project at our premier marine terminal located in the Bahamas, the Bahamas Oil Refining Company International, or BORCO. These initial expansion phases were the most ambitious growth capital projects completed in Buckeye's long history, and I am happy to report they were completed safely, on-time, and on-budget. In addition, we have seen exciting new opportunities for transporting and storing crude oil both domestically, with the resurging domestic crude oil production, and internationally, where BORCO is emerging as a critical staging location for new crude oil production off the coast of South America.

Cash Distribution Coverage[1,2]



[1] See Non-GAAP Reconciliations at end of this report
[2] Distributable cash flow divided by cash distributions declared for the respective periods

These accomplishments are important milestones as Buckeye's nearly 1,300 employees pursue our vision of being the logistical solutions partner of choice for the global energy business. Our mission is to deliver superior returns to our investors through our talented, valued employees and our core strengths of:

- An unwavering commitment to safety, environmental responsibility, regulatory compliance, and personal integrity
- Best-in-class customer service and sophisticated commercial operations
- Operational excellence that provides consistent, reliable performance at the lowest reasonable cost
- An entrepreneurial approach toward logistical solutions to profitably expand and optimize Buckeye's portfolio of global energy assets
- A commitment to consistent execution and the continuous improvement of our operations, projects and people

We are confident that through leveraging these strengths, Buckeye will be successful in 2013 and beyond.

Commitment to Safety

I am pleased to report that Buckeye was able to achieve record financial results in 2012 while maintaining safe, reliable, and environmentally responsible operations. Buckeye's commitment to best-in-class operations is demonstrated by the fact that we continued to improve our performance in key safety areas of injuries and motor vehicle incidents, where we achieved 23 percent and 36 percent year-on-year reductions, respectively, in incident rates for these key performance areas in 2012. Our safety performance continues to outperform industry benchmarks. Safety is a core value and 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 Performance

Buckeye achieved record Adjusted EBITDA[1] for 2012 of $559.5 million, an increase of 15 percent compared to $487.9 million for 2011. This record performance was the result of the increased contribution from our BORCO facility, including the contribution from recently completed storage expansion projects, the full year contribution from the 2011 acquisition of a significant portfolio of terminals and pipelines from BP North America, and the partial year contribution from the Perth Amboy terminal acquisition.

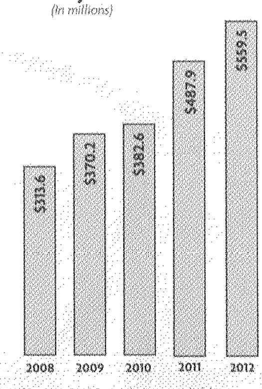
We continued our uninterrupted history of payment of cash distributions in each quarter since becoming a publicly traded partnership in 1986. Distributions paid in 2012 totaled $4.15 per unit, an increase of 12.5 cents per unit, or over three percent, over 2011 cash distributions. As one of the first publicly traded master limited partnerships, Buckeye has the longest track record of consecutive quarterly distributions among our MLP peers.

Growth and Diversification

Perth Amboy Acquisition

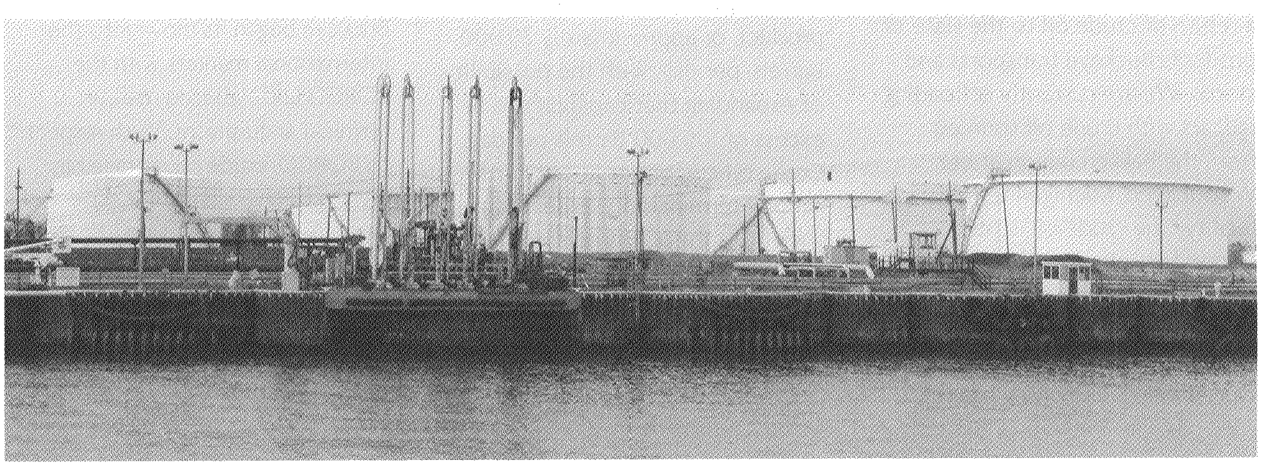
In July 2012, we completed the acquisition of a terminal storage facility with over four million barrels of storage located on the New York Harbor. This terminal improves connectivity and service capabilities and provides security and diversity of product supply for our customers by connecting waterborne product supply with end destination markets across our system. We believe the improved connectivity and service capabilities will increase utilization of our pipeline and terminal system. The facility, located in Perth Amboy, New Jersey, boasts three active docks, including one ship dock with up to 37 feet of draft. Our plans to transform this facility include a direct pipeline link to our Linden complex, which is a key origination point for our Northeast pipeline system. Other significant growth capital projects are planned at the facility to transform it into a highly efficient, multi-product storage, blending, and throughput facility.

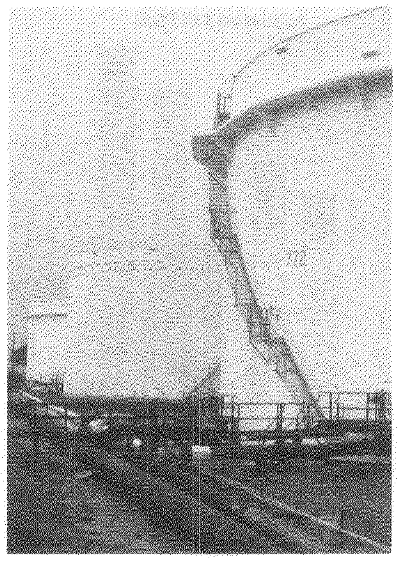
Adjusted EBITDA[1]
(In millions)

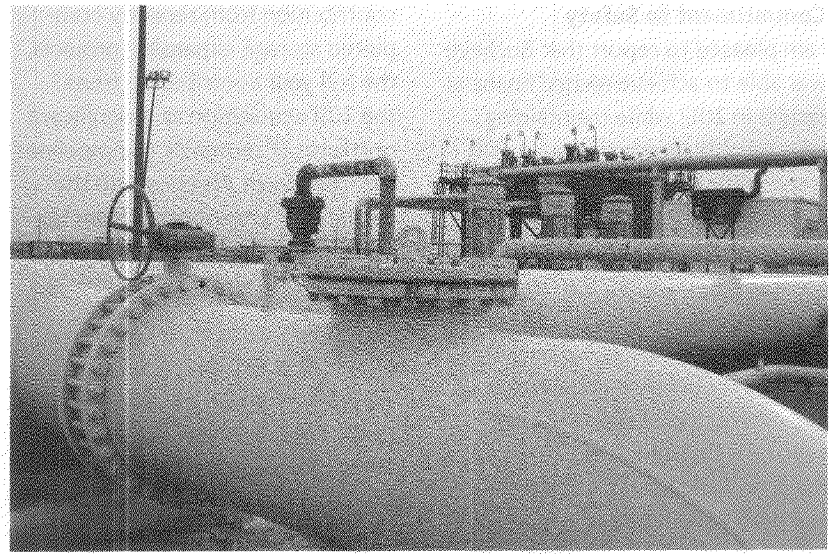


[1] See Non-GAAP Reconciliations at end of this report

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







Repurposing of Assets

Buckeye transported approximately 1.4 million barrels per day of petroleum products in 2012 through our approximately 6,000 miles of pipeline. Our approximately 100 liquid petroleum products terminals handled almost 900,000 barrels per day of products in 2012. Products handled by Buckeye include gasoline; distillates, including diesel fuel, heating oil, and kerosene; jet fuel; and crude oil, for which we have recently seen a resurgence in volumes. Buckeye began operations back in 1886 with a Standard Oil crude oil pipeline from the western Pennsylvania oilfields to Cleveland, Ohio refineries. We are now seeing a return of crude oil to the slate of products Buckeye transports and stores. We are currently offloading railcars with crude oil sourced from the Bakken region at our Woodhaven, Michigan terminal facility. The crude oil is then shipped via pipeline to an Ohio refinery for our customer. We also initiated crude oil activities at our Albany, New York terminal in 2012. Our Albany facility now has the ability to handle unit-train-sized crude oil shipments again sourced from the Bakken region. We offload the crude oil from railcars, store the product at our terminal, and then load the crude oil across our marine dock onto ships or barges for transport to our customer's Saint John, Canada refinery. Both of these success stories are the result of our commercial teams identifying profitable new uses for underperforming assets with minimal additional capital investment.

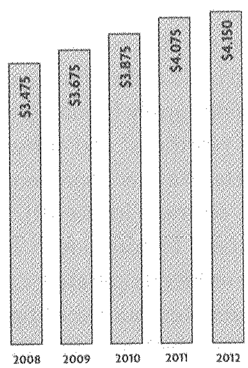
Crude oil is also expected to play an important part in the success of the Perth Amboy terminal transformation, as we expect to be able to offload at least one unit train of product, or approximately 70,000 barrels, per day, with the possibility of expanding that capability to in excess of 100,000 barrels per day. Crude oil customers at our Perth Amboy terminals are expected to then have the ability to ship that product out across our marine dock to waiting ships or barges, or via pipeline or truck to any number of final destinations. The optionality expected to be provided by the Perth Amboy terminal is an important part of the value equation and we believe it will provide our Perth Amboy terminal with a competitive advantage in the marketplace.

We are looking at ways to leverage other domestic Buckeye assets as well, particularly around the Midwest. As production from shale formations, such as from the Bakken and Utica regions, continues to change the domestic crude supply landscape, Buckeye intends to leverage its assets and people to provide crude oil logistic solutions for producers and refiners wherever possible.

International Markets Growth

Buckeye began its move into the international markets with the BORCO and Yabucoa marine terminal acquisitions. With respect to BORCO, crude oil storage has always been a significant aspect of this business, comprising just over a fifth of leased capacity at the facility for 2012. We expect that percentage will increase as we believe crude oil storage and services to be a significant growth opportunity in

Cash Distributions Per Unit



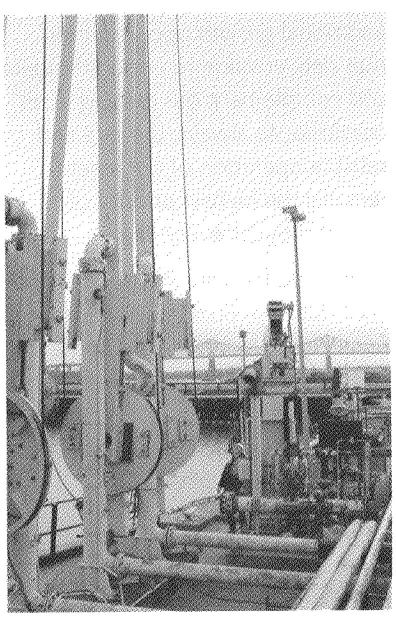
the coming years with the ramp-up in crude production on a global basis. In 2012, we announced the execution of an important long-term agreement with a customer for significant crude oil storage at BORCO. This agreement supports the construction of additional expansion capacity as well as making use of substantial existing tankage. BORCO is expected to act as a staging and blending hub for this customer, which has new production coming on-line off the coast of South America. BORCO is uniquely positioned to serve as a crude oil staging hub due to its location and its capabilities, including redundant deep water berthing and high-speed loading and offloading pumping capabilities.

At Yabucoa, we added a new crude oil storage customer and a jet fuel storage customer, which utilizes our facility to supply the San Juan airport. In addition, we enjoyed the initial earnings contribution in 2012 from our fuel oil marketing business, where we primarily secure supply for utility plants in the Caribbean in back-to-back transactions. We are in the beginning stages of this new business and expect an increase in earnings as we ramp up this business in 2013.

Business Segment Review

The following is a summary of our operating highlights for 2012[2]:

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



Buckeye achieved record Adjusted EBITDA for 2012 of $559.5 million, an increase of 15 percent compared to $487.9 million for 2011.

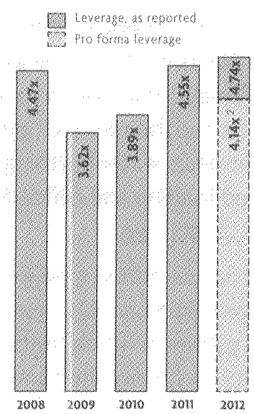
PIPELINES & TERMINALS

- Adjusted EBITDA from our Pipelines & Terminals segment was $409.1 million in 2012 compared to $361.0 million the previous year. Pipeline volumes increased by approximately two percent primarily as a result of a full year contribution from pipelines acquired in 2011. Strength in gasoline volumes drove the increase as distillates and jet fuel volumes were relatively flat. Terminalling volumes increased by 23 percent, benefiting from a full year contribution from the BP terminals acquired in June 2011. Results for the year also benefited from higher pipeline tariff rates and terminalling contract rate escalations, although tariff increases were limited to operating systems other than Buckeye Pipe Line Company, L.P. as a result of a 2012 FERC Order. This order now has been substantially resolved, allowing for tariff increases in 2013 on all of our pipelines. Our tariffs for transportation of jet fuel from New Jersey to three New York City area airports remain subject to an ongoing complaint, which is currently the subject of formal settlement efforts at FERC.
- Internal growth capital projects are expected to be a significant driver of increased cash flows for 2013, as we expect to add to our butane blending capabilities at additional terminals across our system. In addition, a propylene rail and storage facility completed in late 2012 and the transformation of our Perth Amboy terminal are expected to provide incremental contribution to earnings in late 2013.

INTERNATIONAL OPERATIONS

- Our International Operations segment, which includes results of our BORCO and Yabucoa marine terminals, produced $132.1 million of Adjusted EBITDA in 2012, an increase of 17 percent over 2011. This increase was primarily the result of almost two million barrels of expansion storage capacity that became operational during the second half of 2012 as well as increased facility utilization.
- We expect incremental Adjusted EBITDA in 2013 from an additional 2.8 million barrels of expansion storage capacity expected to become operational in 2013[3].

Net LT Debt/Adjusted EBITDA[1]



[1] Long-term debt less cash and cash equivalents divided by Adjusted EBITDA (adjusted for pro forma impacts of acquisitions), calculation as per BPL Credit Facility

[2] Pro forma leverage as of December 31, 2012, to reflect impact of $350 million January 2013 equity issuance

NATURAL GAS STORAGE

- Adjusted EBITDA from our Natural Gas Storage segment was $6.1 million for 2012 compared to $4.2 million in 2011. Although this segment showed improvement over 2011, it continues to be negatively impacted by low natural gas prices, depressed seasonal spreads, and lack of price volatility.

ENERGY SERVICES

- Our Energy Services segment produced $0.5 million of Adjusted EBITDA for the year compared to $1.8 million in the prior year. 2012 results were impacted by backwardated market conditions and sustained basis weakness driven by changing supply fundamentals in the Northeast and Midwest markets. We saw improvement in this segment in late 2012 that we expect to continue in 2013 as we reduced operating costs and executed our risk mitigation strategy, which included focusing on fewer, more strategic locations with less expected basis volatility.

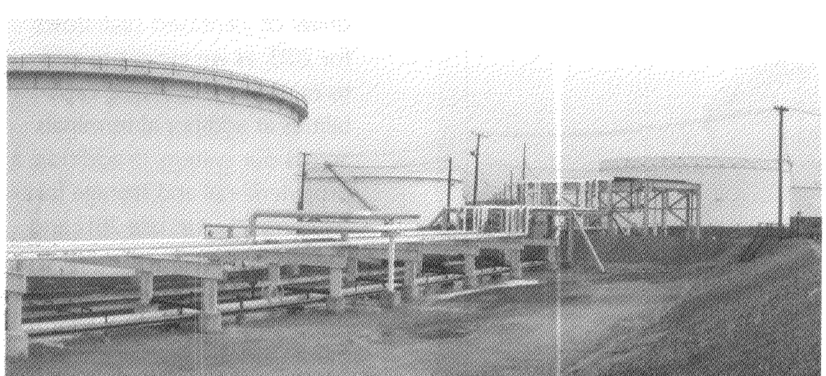
[3] Approximately 1.6 million barrels of expansion storage was operational in the first quarter of 2013.

DEVELOPMENT & LOGISTICS

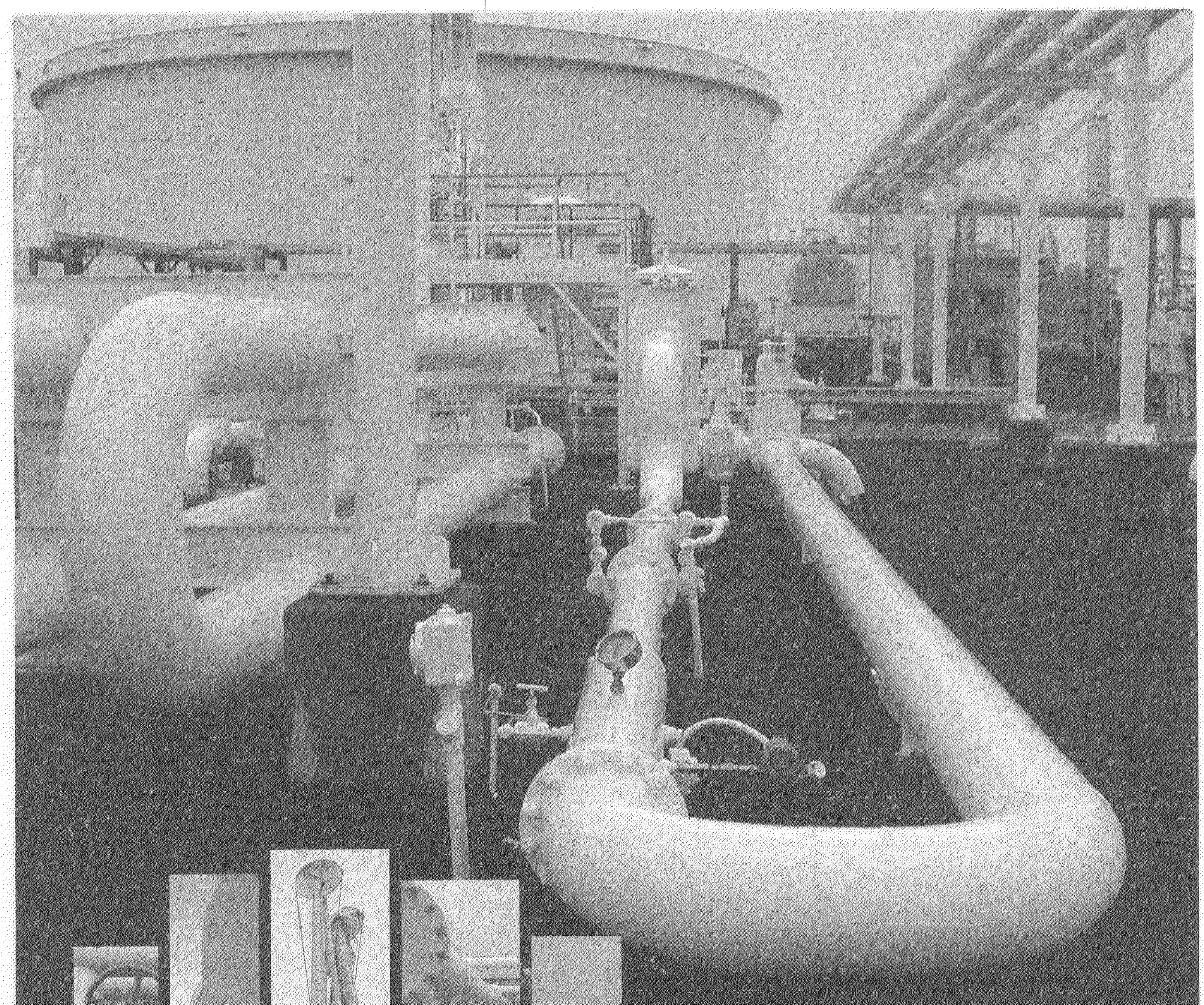
- Our Development & Logistics segment continues to show improved performance and earned $11.7 million of Adjusted EBITDA for 2012, compared to $7.9 million in 2011, from the contract operation of third-party pipelines and propane storage revenues from recent acquisitions.

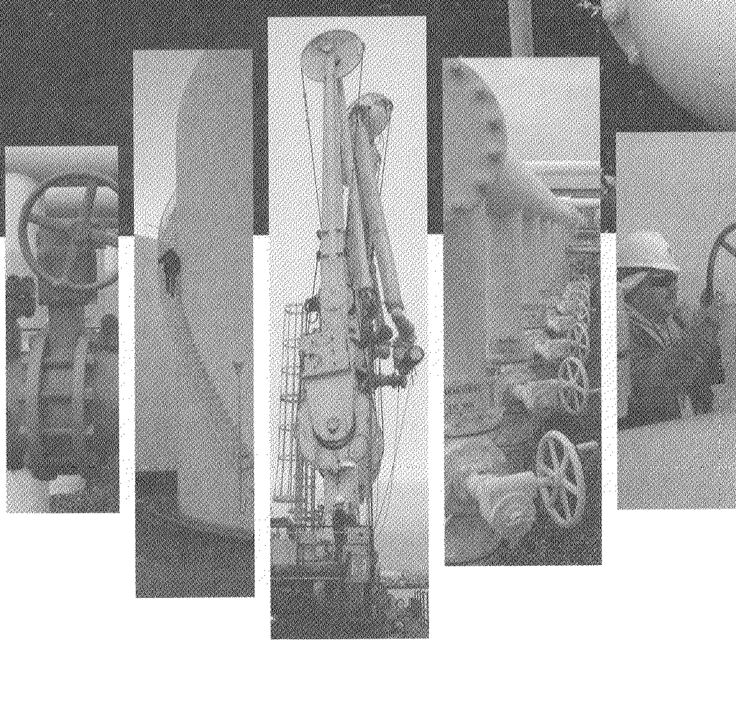
Our top priorities for 2013 include continuing to deliver on our expansion and enhancement projects at BORCO and our transformation project at our new Perth Amboy facility. We also expect to pursue additional growth opportunities that deliver value to our unitholders and complement our existing asset portfolio. As always, the safe and reliable operation of our assets remains the highest priority of our employees every day.

Thank you for your investment and confidence in Buckeye. We look forward to updating you on the execution of our strategy throughout 2013.



Clark C. Smith
President and Chief Executive Officer





2012 Form 10-K

BUCKEYE PARTNERS, L.P.

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, 2012

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 (State or other jurisdiction of incorporation or organization)	**23-2432497** (IRS Employer Identification number)
One Greenway Plaza **Suite 600** **Houston, TX** (Address of principal executive offices)	**77046** (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, 2012, the aggregate market value of the registrant's limited partner units and Class B units held by non-affiliates was $5.0 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 19, 2013: 97,322,040 and 7,974,750, respectively.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement being prepared for the solicitation of proxies in connection with the 2013 Annual Meeting of Limited Partners are incorporated by reference in Part III of this Form 10-K.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information contained in this Annual Report on Form 10-K (this "Report") 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: (i) changes in federal, state, local, and foreign laws or regulations to which we are subject, including those governing pipeline tariff rates and those that permit the treatment of us as a partnership for federal income tax purposes, (ii) terrorism, adverse weather conditions, including hurricanes, environmental releases and natural disasters, (iii) changes in the marketplace for our products or services, such as increased competition, better energy efficiency, or general reductions in demand, (iv) adverse regional, national, or international economic conditions, adverse capital market conditions, and adverse political developments, (v) shutdowns or interruptions at our pipeline, terminal, and storage assets or at the source points for the products we transport, store, or sell, (vi) unanticipated capital expenditures in connection with the construction, repair, or replacement of our assets, (vii) volatility in the price of refined petroleum products and the value of natural gas storage services, (viii) nonpayment or nonperformance by our customers, (ix) our ability to integrate acquired assets with our existing assets and to realize anticipated cost savings and other efficiencies and benefits, (x) our ability to successfully complete our organic growth projects and to realize the anticipated financial benefits, and (xi) an unfavorable outcome with respect to the proceedings pending before the Federal Energy Regulatory Commission ("FERC") regarding Buckeye Pipe Line Company, L.P.'s tariff rates. 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. 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 Item 6 of this Report 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 6,000 miles of pipeline and over 100 active products terminals that provide aggregate storage capacity of over 70 million barrels. We also operate and/or maintain 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 global logistics hub.

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;
- Pursuing other energy-related assets that enable us to leverage our asset base, knowledge base and skill sets; and
- Providing superior customer service.

Recent Developments

2013 Transaction

Equity Offering

In January 2013, we completed a public offering of 6,000,000 LP Units pursuant to an effective shelf registration statement, which priced at $52.54 per unit. The underwriters also exercised an option to purchase 900,000 additional LP Units, resulting in total gross proceeds of approximately $362.5 million before deducting underwriting fees and estimated offering expenses. We used the net proceeds from this offering to reduce the indebtedness outstanding under our revolving credit facility.

2012 Transactions

Acquisitions

In July 2012, we acquired a marine terminal facility for liquid petroleum products in New York Harbor (the "Perth Amboy Facility") from Chevron U.S.A. Inc. ("Chevron") for $260.3 million in cash. The facility, which sits on approximately 250 acres on the Arthur Kill tidal strait in Perth Amboy, New Jersey, has over 4.0 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 six miles from our Linden, New Jersey complex. The facility provides a link between our inland pipelines and terminals and our BORCO facility in The Bahamas and opportunities for improved service offerings to our customers. Concurrent with the acquisition, we entered into multi-year storage, blending, and throughput commitments with Chevron.

In September 2012, our operating subsidiary, Buckeye Pipe Line Holdings, L.P. ("BPH"), purchased an additional 20% ownership interest in WesPac Pipelines – Memphis LLC ("WesPac Memphis") from Kealine LLC for $17.3 million and, as a result of the acquisition, our ownership interest in WesPac Memphis increased from 50% to 70%. Since BPH retains controlling interest in WesPac Memphis, this acquisition was accounted for as an equity transaction.

Equity Offering

In 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 at a price of $58.65 per LP Unit, before deducting placement agents' fees and estimated offering expenses. We used the majority of the net proceeds from this offering to reduce the indebtedness outstanding under our Revolving Credit Agreement dated September 26, 2011 (the "Credit Facility") with SunTrust Bank and to indirectly fund a portion of the Perth Amboy Facility acquisition as well as certain other growth capital expenditures.

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 and, from time to time, our International Operations segment sells fuel oil to third parties at various locations in the Caribbean. Detailed financial information regarding revenue and total assets of each segment can be found in Note 24 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,					
	2012		2011		2010	
	Revenue	Percent	Revenue	Percent	Revenue	Percent
Pipelines & Terminals	$ 719,126	16.5%	$ 631,289	13.2%	$ 574,990	18.3%
International Operations (1)	254,362	5.8%	193,960	4.1%	936	0.0%
Natural Gas Storage	71,339	1.6%	65,990	1.4%	95,337	3.0%
Energy Services	3,293,274	75.6%	3,888,961	81.7%	2,481,566	78.7%
Development & Logistics	50,211	1.2%	43,068	0.9%	37,696	1.2%
Intersegment	(31,070)	(0.7)%	(63,658)	(1.3)%	(39,257)	(1.2)%
Total	$ 4,357,242	100.0%	$ 4,759,610	100.0%	$ 3,151,268	100.0%

(1) Amounts for 2012 include sales related to the fuel oil supply and distribution services in the Caribbean.

Pipelines & Terminals Segment

The Pipelines & Terminals segment owns and operates approximately 6,000 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, as well as crude oil. 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 over 40.0 million barrels. In addition, two of our terminals provide crude oil services, including train off-loading, storage and throughput. 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 transports those products to other locations for a fee.

The following table presents product volumes transported and percentage of products transported by the pipelines in the Pipelines & Terminals segment for the periods indicated (barrels per day ("bpd") in thousands):

	Year Ended December 31,					
	2012		2011		2010	
Pipelines:						
Gasoline	701.9	50.6%	668.1	49.2%	653.5	49.6%
Jet fuel	339.2	24.5%	340.6	25.1%	338.5	25.7%
Middle distillates (1)	322.3	23.3%	327.2	24.1%	303.4	23.1%
Other products (2)	22.2	1.6%	22.2	1.6%	21.0	1.6%
Total pipelines throughput	1,385.6	100.0%	1,358.1	100.0%	1,316.4	100.0%

(1) Includes diesel fuel, heating oil and kerosene.
(2) Includes liquefied petroleum gas ("LPG").

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 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, via a connecting carrier, respectively.

The Laurel pipeline system transports refined petroleum products through a 350-mile pipeline extending westward from three refineries, a marine terminal 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, BPL Transportation 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 refineries and other pipeline connection points near Toledo and Lima, Ohio; Detroit, Michigan; and East Chicago, Indiana. Major market areas served include Huntington/Fort Wayne, Indianapolis and South Bend, Indiana; Bay City, Detroit and Flint, Michigan; Cleveland, Columbus, Lima, Warren and Toledo, Ohio; and Pittsburgh, Pennsylvania.

Our operating subsidiary Wood River Pipe Lines LLC ("Wood River") owns 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 the East St. Louis, Illinois area and transported to the Chicago area (the "Chicago Complex"), to our terminal in the St. Louis, Missouri area and to the Lambert-St. Louis Airport, to delivery points across Illinois and Indiana and to our pipeline in Lima, Ohio, and from the Chicago Complex 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, BPL Transportation owns a 650-mile refined product pipeline that originates in Dubuque, Iowa and runs southwest into Missouri and then northwest back into Iowa, serving the Sugar Creek, Missouri, and Council Bluffs and Des Moines, Iowa markets. BPL Transporation also has a 124-mile pipeline that runs from Portland, Maine to 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. In September 2012, BPH purchased an additional 20% ownership interest in WesPac Memphis from Kealine, increasing our ownership interest in WesPac Memphis from 50% to 70%. 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,		
	2012	2011	2010
Products throughput (1)	897.3	730.9	562.5

(1) Amounts for 2012 and 2011 include throughput volumes at terminals acquired from BP and ExxonMobil Corporation ("ExxonMobil") on June 1, 2011 and July 19, 2011, respectively. The table does not include throughput at the five terminals owned by the Energy Services segment, discussed below.

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

Location	Number of Terminals (1)	Storage Capacity
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 Jersey (2)	1	4,530
New York	10	4,111
Ohio	14	4,003
Pennsylvania	11	2,536
South Carolina	3	1,022
Tennessee (3)	1	328
Virginia	3	781
Wisconsin	4	1,228
Total	100	41,896

(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 or the BORCO facility that are included in the International Operations segment for reporting purposes (as discussed below) with an aggregate storage capacity of approximately 30.0 million barrels.

(2) In July 2012, we acquired a marine terminal facility for liquid petroleum products in Perth Amboy, New Jersey.

(3) This represents the terminal facility owned by WesPac Memphis, which is 70% owned by BPH.

Equity Investments

We own a 34.6% equity interest in West Shore Pipe Line Company ("West Shore"). 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 an 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 owns a terminal in South Portland, Maine that has approximately 725,000 barrels of storage capacity.

International Operations Segment

The International Operations segment provides marine terminal throughput services, marine bulk storage and other related services through two petroleum product terminals located on Grand Bahama Island, in The Bahamas and in Puerto Rico.

The following table sets forth terminal locations and storage capacity in barrels for terminals reported in the International Operations segment (barrels in thousands):

Location	Storage Capacity
Bahamas	24,946
Puerto Rico	4,623
Total	29,569

BORCO Facility

BORCO owns a terminal facility located along the Northwest Providence Channel of Grand Bahama Island, which it uses to operate a fully integrated terminalling business, and offers customers storage and ancillary services including, but not limited to, berthing, heating, transshipment, blending, treating and bunkering. Ancillary services provided by BORCO facilitate customer activities within the tank farm and at the jetties.

BORCO's terminal facility includes more than 80 aboveground storage tanks, which store crude oil, fuel oil and refined petroleum products. The existing marine infrastructure of BORCO's terminal facility consists of three deep-water jetties, which provide six deep-water berths that serve as the access points to the storage facilities. Certain of these jetties are capable of handling both very large crude carriers ("VLCCs") and ultra large crude carriers ("ULCCs").

We own the property on which the BORCO terminal facility is located. BORCO leases 330 acres of seabed on which the deep water jetties are located and has a long-term agreement through 2057 with the Bahamas Government. BORCO also leases the land on which the inland dock is located and has a long-term agreement through 2067 with the Freeport Harbour Company.

Yabucoa Terminal

The Yabucoa terminal includes 44 storage tanks, which store gasoline, jet fuel, diesel, fuel oil and crude oil. Access to the Yabucoa terminal is provided through one ship dock, which is leased from the Puerto Rico Ports Authority, two barge docks as well as an 8-bay truck rack. Additionally, we provide fuel oil supply and distribution services to utility companies in the Caribbean.

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 30.0 billion cubic feet ("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 million cubic feet ("Mmcf") per day and 750 Mmcf/day, respectively, utilizing over thirty wells. Thirty-one miles of pipeline link the original Lodi facility to an interconnect with PG&E just north of Antioch, California. Six miles of pipeline link 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 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 revenue consists 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 certain areas served by our pipelines and terminals which allows us to increase the utilization of our existing pipeline and terminal assets by marketing refined petroleum products in the areas served by those assets. The segment's customers consist principally of product wholesalers and major commercial users of refined petroleum products including gasoline, propane, ethanol, biodiesel and petroleum distillates such as heating oil, diesel fuel and kerosene. The Energy Services segment owns five terminals in Pennsylvania with aggregate storage capacity of approximately 1.0 million barrels, which are operated by the Pipelines & Terminals segment. 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,		
	2012	2011	2010
Sales volumes	1,106.3	1,337.8	1,139.1

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 to commercial customers, construction companies, school districts and trucking companies; 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 hedging 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 provides turn-key operations and maintenance, asset development and construction services for third-party pipeline and energy assets across the United States. This segment operates and/or maintains third-party pipelines under agreements with major oil and gas, petrochemical and chemical companies, which 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 as well as other energy companies in the United States. The Development & Logistics segment includes our ownership and operation of two underground propane storage caverns in Huntington, Indiana and Tuscola, Illinois, with approximately 800,000 barrels of throughput and storage capability. Additionally, this segment owns an approximate 63% interest in the Sabina crude butadiene pipeline, owns and operates a 30-mile ammonia pipeline and owns and operates approximately 25 miles of pipeline, which it leases to third parties, all located in Texas.

Third-party operations and construction management 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 operation and maintenance service customers.

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 and within the New York City area, the Pittsburgh area 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, Maine terminals, and the pipeline connecting these 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 on Grand Bahama Island, Bahamas faces competition with some proprietary and third-party independent terminal operators in the Caribbean region. The facility's location and deep draft coupled with its storage and blending capability provide 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.

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.

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 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, 2012, 2011 and 2010, 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 does not vary significantly.

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 tend 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.

The Pipelines & Terminals and Energy Services segments both benefit from butane blending activities at our terminals during the winter months. From mid-September through mid-March, we are able to blend butane into various grades of gasoline.

Employees

Except as noted below, we are managed and operated by employees of Buckeye Pipe Line Services Company ("Services Company"). We reimburse Services Company for the cost of providing employee services pursuant to a services agreement. At December 31, 2012, Services Company had approximately 1,020 employees, approximately 190 of whom were represented by labor unions. Additionally, at December 31, 2012, certain of our wholly owned subsidiaries had approximately 230 employees, approximately 170 of whom are employed at our BORCO facility. We have never experienced any work stoppages or other significant labor problems.

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 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.

Until recently, Buckeye Pipe Line's rates have been 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 was determined by FERC not to have significant market power, individual rate increases: (a) would not exceed a real (i.e., exclusive of inflation) increase of 15% over any two-year period, and (b) would be allowed to become effective without suspension or investigation if they did 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 would be presumptively valid upon a showing that the proposed rate exceeds marginal costs. In markets where Buckeye Pipe Line was determined by FERC to have significant market power and in certain markets where no market power finding was made: (i) individual rate increases could not 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 was determined by FERC not to have significant market power were required to be accompanied by a corresponding decrease in all of Buckeye Pipe Line's rates in markets where it was found to have significant market power and in certain markets where no market power finding was made. Shippers retained the right to file complaints or protests following notice of a rate increase, but were 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 were unduly discriminatory, or that Buckeye Pipe Line had 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. By order issued on March 30, 2012 in FERC Docket No. IS12-185-000, FERC required Buckeye Pipe Line to show cause why its program should not be discontinued and other changes made to its rates and system of regulation. On February 22, 2013, FERC issued an order in Dkt. Nos. IS12-185-000, *et al.*, discontinuing the Buckeye Pipe Line program but permitting Buckeye Pipe Line to retain its filed rates, to make future rate changes in markets which were previously determined by FERC to be competitive under market-based ratemaking authority, and to make future changes in rates in other markets under the generic FERC ratemaking methods, which would include indexing. We cannot predict with certainty the impact of the discontinuance of Buckeye Pipe Line's rate program on Buckeye Pipe Line's operations. Independent of regulatory considerations, it is expected that tariff rates will continue to be constrained by competition and other market factors.

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

Lodi Gas owns and operates a natural gas storage facility in Northern California under a Certificate of Public Convenience and Necessity originally granted by the CPUC. 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 for inspection and maintenance and to comply with such plans and programs. Also governed by the Acts and related regulations are requirements for an integrity management program that among other things, requires the determination of pipeline integrity risk and periodic assessments of pipeline segments in High Consequent Areas ("HCAs"), 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 and a control room management plan that prescribes safety requirements for controllers, control rooms and the computer systems used to monitor and control pipeline operations.

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 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 $100.0 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, 2013. 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. 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, 2013. 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.

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 and weakness in the United States economy may adversely affect our business.

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 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.

At BORCO, recent increases in demand for the services we provide has been driven by increases in crude oil production from Latin America, crude oil movements from South America to Asia, and Latin America demand for clean petroleum products from the United States and Europe. Changes in these and other 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 and the prices we can charge for those services.

In recent years, the federal government has enacted renewable fuel or energy efficiency statutory mandates that 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 of the 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.

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.

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, our South Portland and Bangor, Maine terminals are 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, which has accelerated in recent years, has altered distribution patterns, reducing demand for transportation services in some markets and increasing them in other markets.

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 delivering refined petroleum products to end-users such as retail gasoline stations.

Our International Operations segment primarily competes with other marine terminals in the Caribbean, and to the lesser extent, terminals on the Gulf Coast. Many competitive terminals are owned by major integrated oil and gas companies, refiners and master limited partnerships. Although the International Operations segment's storage fees are not regulated, the segment is subject to price competition from competitive terminals. Our International Operations segment also competes with alternatives to terminal storage of crude oil and refined petroleum products, such as floating storage and lightering, which could reduce demand for our Caribbean terminal services.

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 Adjusted EBITDA (see "Non-GAAP Financial Measures" in Item 7 for a discussion of Adjusted EBITDA, which is our primary measure of performance), 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 prohibit 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.

We performed a certain level of diligence in connection with our acquisitions and attempted to ascertain the extent of liabilities that might be associated with an acquired facility, but there may be unknown and contingent liabilities related to our acquisitions of which we are unaware.

If a significant release or event occurred in the past at any of our acquired assets 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, financial condition, results of operations or cash flow.

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, including the integration of acquired assets into our existing business, may require substantial capital or the incurrence of substantial indebtedness. If we consummate any future acquisitions, our capitalization and results of operations may change significantly.

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

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

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

Our rate structures are subject to regulation and change by FERC; required changes could be adverse.

Buckeye Pipe Line, Wood River, BPL Transportation and NORCO are interstate common carriers regulated by FERC under the Interstate Commerce Act, the Energy Policy Act of 1992 and the Department of Energy Organization Act. FERC's primary ratemaking methodology is indexing rates for inflation. 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. A pipeline may also charge rates based on the agreement of all shippers receiving a service, which are referred to as settlement-based rates.

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 Producer Price Index ("PPI") – finished goods 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 potentially hampering our ability to recover our costs by relying on the index. Where circumstances justify it, FERC permits pipelines to use one of three alternatives to indexing—pipelines may seek to use market-based, cost-based, or settlement-based rates.

Until recently, Buckeye Pipe Line has been 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. In 1991, Buckeye Pipe Line sought and received FERC permission to determine rate changes on Buckeye Pipe Line's pipeline system (the "Buckeye System") using a unique methodology that constrained rates based on competitive pressures in markets that FERC found to be competitive, as well as certain other limits on rate increases in other markets on the Buckeye System (the "Buckeye Methodology"). FERC permitted the continuation of the Buckeye Methodology for the Buckeye System in 1994, subject to FERC's authority to cause Buckeye Pipe Line to terminate the Buckeye Methodology in the future. The Buckeye Methodology was an exception to the generic oil pipeline regulations that FERC issued under the Energy Policy Act of 1992 (the "FERC Rules"), which rely primarily on the indexing methodology described above.

On March 1, 2012, Buckeye Pipe Line filed to increase its rates under the Buckeye Methodology. On March 30, 2012, in response to a shipper protest, FERC issued an order (the "Show Cause Order") in Docket No. IS 12-185-000 rejecting the rate increase and stating that FERC will review the continued efficacy of the Buckeye Methodology. The Show Cause Order directed Buckeye Pipe Line to show cause why it should not be required to discontinue the Buckeye Methodology and avail itself of the generic ratemaking methodologies used by other oil pipeline companies. Pending FERC's review of the program, the Order also disallowed proposed rate increases on the Buckeye System that would have become effective April 1, 2012. On September 20, 2012, five airlines jointly filed a complaint in FERC Docket No. OR12-28-000 alleging that Buckeye Pipe Line's rates for the transportation of jet fuel to the three major New York City area airports were unreasonable and should be reduced and should be subject to reparations for past shipments, and that the Buckeye Methodology should end with respect to that transportation; on October 10, 2012, Buckeye Pipe Line filed a motion to dismiss and answer opposing the complaint and its relief, and subsequent pleadings were filed by both the airlines and by Buckeye Pipe Line. On October 15, Buckeye Pipe Line filed an application in FERC Docket No. OR13-3-000 for authority to charge market-based rates for transportation to destinations in the New York City Market, including the New York City area airports, because Buckeye Pipe Line lacked significant market power. On December 14, 2012, five airlines intervened and filed comments in opposition to the application in Docket No. OR13-3-000. As of the end of 2012, FERC had not issued an order with respect to Docket Nos. IS12-185-000, OR12-28-000, or OR13-3-000. On February 22, 2013, FERC issued an order in Dkt. No. IS12-185-000, *et al.*, discontinuing the Buckeye Pipe Line Program and affirming on rehearing its rejection of all rate increases filed in March 2012 ("Ratemaking Methodology Order"). The Ratemaking Methodology Order permitted Buckeye to retain its currently-filed rates in place, to make future rate changes in markets previously found to be competitive by FERC under market-based ratemaking authority, and to make future changes in rates in other markets pursuant to the generic FERC ratemaking methods, which would include indexing. Also on February 22, 2013, FERC issued an order setting the airline complaint in Dkt. No. OR12-28-000 for hearing, but holding the hearing in abeyance and setting the dispute for settlement procedures before a settlement judge. It is too early to predict the outcome of the proceedings in FERC Docket Nos. OR12-28-000 and OR 13-3-000, or to determine the impact of the Ratemaking Methodology Order's requirement that Buckeye Pipe Line transition to ratemaking methodologies that differ from the Buckeye Methodology.

In addition to the risks described above, at any time shippers on any of our FERC-regulated pipelines have the right to challenge the application of the index to a pipeline's rates or the underlying rates themselves as being unjust and unreasonable, subject to the FERC's cost-of-service standards. Following the Ratemaking Methodology Order, shippers would have the right to file such complaints regarding rates in Buckeye Pipe Line's markets that are not subject to market-based-rate authority. Such shipper challenges may seek adjustments to our rates prospectively and, subject to limitations, for certain past periods. If a significant shipper challenge were to result in an outcome that is unfavorable to us, our business, financial condition, results of operations and/or cash flows could be adversely impacted.

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.

In recent years, federal authorities such as the EPA and various state regulatory bodies have increasingly sought to regulate emissions of carbon dioxide, methane and other "greenhouse gases" ("GHG"). Such regulation has targeted emissions from large industrial sources, such as factories, refineries and other manufacturing facilities, and for increasingly large classes of motor vehicles.

These currently effective regulations 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 (for motor vehicles or otherwise) could include efficiency requirements or other methods of curbing carbon emissions that could adversely affect demand for the refined petroleum products, natural gas and other hydrocarbon products that we transport, store or otherwise handle in connection with our business. A significant decrease in demand for petroleum products would have a material adverse effect on our business, financial condition, results of operations or cash flows.

Environmental regulation may impose significant costs and liabilities on us.

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

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

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

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

DOT and state-level regulations may impose significant costs and liabilities on us.

Our pipeline operations and natural gas storage operations are subject to regulation by the DOT and by some of the states in which we do business. Certain states, particularly California, have been reviewing pipeline safety regulations and increasing inspections and audits. 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.

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.

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.

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. 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.

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 76% of BORCO's total revenue for the year ended December 31, 2012. Currently, BORCO has a limited number of long-term storage customers, consisting of major oil companies, energy companies, physical traders and one national oil company. For the year ended December 31, 2012, approximately 32% and 66% of BORCO's 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 cyber security 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. Cyber security 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 2012 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.

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.

Derivative reform mandated by the Dodd-Frank Act and rules and regulations under the Act may have an adverse effect on our ability to use certain derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act") and the rules and regulations promulgated and to be promulgated under the Act may have an adverse effect on our ability to use certain derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. The Act mandates significant changes to the over-the-counter derivative market. Among other changes, the Act and the regulations under the Act will:

- require the clearing and exchange trading of certain derivatives;
- require dealers and major participants to register with the Commodity Futures Trading Commission or the Securities Exchange Commission or both, and require them to comply with capital, business conduct, reporting and recordkeeping requirements;
- subject certain derivative transactions to margin requirements;
- establish position limits for certain derivatives; and
- require certain financial institutions to spin-off portions of their derivatives business.

The rulemaking process under the Act has not been completed, and the timeframes for compliance with rules under the Act that are effective remains uncertain. Consequently, it is not possible at this time to determine the full effect that the Act and the rules and regulations adopted under the Act will have on our ability to continue to use the derivative products we currently utilize. As a result of the imposition of capital, clearing and exchange-trading requirements, the Act and the rules and regulations under the Act may limit the availability of certain derivative products and/or may increase the costs of such products. Additionally, the margin requirements applicable to certain derivative products may increase, resulting in such products becoming more expensive or uneconomical for us to use in our business. Any requirement to post more collateral to our counterparties in excess of what we currently post to collateralize our obligations may have a negative impact upon our liquidity. Position limits may be imposed upon certain derivative transactions, which may further restrict our ability to utilize these products. To the extent that our dealer counterparties are required to spin-off their derivatives activities to a separate entity, that new entity may not be as creditworthy as the current dealer counterparty and, as a result, we may have to increase our exposure to less creditworthy counterparties or curtail our dealings with that counterparty. The effects of the Act and the rules and regulations under the Act may also reduce our ability to monetize or restructure our existing derivative contracts. If, as a result of the Act and the rules and regulations under the Act, we reduce our use of certain derivatives, 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. To the extent that we currently utilize exchange traded futures in our business, we do not anticipate that those products will be affected by the provisions of the Act and the rules and regulations under the Act described above.

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.

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

We depend on PG&E's intrastate gas pipelines to move our customers' natural gas to and from our Lodi 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 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 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 business, financial condition, results of operation or cash flows.

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 marine terminals, 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 condition, results of operation or cash flows.

Increases in interest rates could adversely affect our unit price and our business.

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.

Additionally, 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.

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. Additionally, noncompliance with such practices and policies by our employees or agents may create additional risk. We cannot make any assurances that we will detect and prevent all violations of our risk management practices and policies, particularly if deception or other intentional misconduct is involved. Any violations of these practices or policies by our employees or agents could result in significant financial losses.

Risks Relating to Partnership Structure

We may sell additional 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.

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.

The tax treatment of publicly traded partnerships or an investment in our LP units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. For example, one such previously introduced legislative proposal would eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units. Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes.

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 the subject of a securities loan (e.g., a loan 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 there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose LP Units are the subject of a securities loan may be considered as having disposed of the loaned LP Units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those LP Units during the period of the loan and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, 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 the unitholder's 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 56,000 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 seabed on which the jetties are located and the inland dock under long-term agreements through 2057 and 2067, respectively.

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.

On May 25, 2012, a ship allided with a jetty at our BORCO facility while berthing, causing damage to portions of the jetty. The extent of the damage is being assessed and presently is estimated to range between $20.0 million and $30.0 million. We have insurance to cover this loss, subject to a $5.0 million deductible. On May 26, 2012, we commenced legal proceedings in The Bahamas against the vessel's owner and the vessel to obtain security for the cost of repairs and other losses incurred as a result of the incident. Full security for our claim has been provided by the vessel owner's insurers, reserving all of their defenses, but the vessel owner is claiming it is entitled to limit its liability to approximately $17.0 million. We also have notified the customer on whose behalf the vessel was at the BORCO facility that we intend to hold them responsible for all damages and losses resulting from the incident pursuant to the terms of an agreement between the parties. Any disputes between us and our customer on this matter are subject to arbitration in Houston, Texas. At this time, we have not experienced any material interruption of service at the BORCO facility as a result of the incident and have commenced the process of repairing the jetty. We recorded a $4.2 million loss on disposal due to the assets destroyed in the incident and $3.5 million related to other costs incurred; however, since we believe recovery of our losses is probable, we recorded a corresponding receivable. To the extent the proceeds from the recovery of our losses is in excess of the carrying value of the destroyed assets or other costs incurred, we will recognize a gain when such proceeds are received and are not refundable. As of December 31, 2012, no gain had been recognized.

On December 3, 2012, a complaint was filed in the Circuit Court for Washington County, Wisconsin by Chad Altschafl, et al., as plaintiffs, naming Buckeye, Buckeye Pipe Line Services Company, BPH, Buckeye Pipe Line and West Shore, as defendants. The complaint in the Altschafl case attempts to allege various emotional distress and property damage claims under Wisconsin law arising out of a release of gasoline from a pipeline operated by West Shore in the Town of Jackson, Wisconsin on July 17, 2012. Owners of 148 properties in the area of Jackson, Wisconsin are the plaintiffs in the case. No dollar amount of damages is stated in the complaint, but the plaintiffs seek damages to reimburse them for, among other things, the costs of restoring their properties and of installing a permanent supply of potable water, the diminution in value of their properties, and the cost of a program of future medical monitoring. The plaintiffs also seek punitive damages. On January 21, 2013, we filed an answer to the complaint, denying its claims and asserting affirmative defenses, and a motion to dismiss the claims for emotional distress and for medical monitoring costs. No hearing on that motion has yet been held and the case is not presently scheduled for trial. The timing or outcome of final resolution of this matter cannot reasonably be determined at this time. Buckeye, Services Company, BPH and Buckeye Pipe Line are entitled to certain indemnifications by West Shore pursuant to an agreement between Buckeye Pipe Line and West Shore, which we believe would result in West Shore indemnifying us for any losses stemming from this litigation. In addition, West Shore has insurance that we believe should cover such losses, subject to a $3.0 million deductible. West Shore is pursuing that insurance coverage.

Federal Energy Regulatory Commission ("FERC") Proceedings

FERC Docket No. IS12-185 – Buckeye Pipe Line Show Cause Proceeding. On March 30, 2012, FERC issued an order (the "Show Cause Order") regarding the market-based methodology used by Buckeye Pipe Line to set tariff rates on its pipeline system (the "Buckeye System"). In 1991, Buckeye Pipe Line sought and received FERC permission to determine rate changes on the Buckeye System using a unique methodology that constrained rates in markets not found to be competitive based on rate changes in markets that FERC found to be competitive, as well as certain other limits on rate increases. FERC ordered the continuation of this methodology for the Buckeye System in 1994, subject to FERC's authority to cause Buckeye Pipe Line to terminate the program in the future. The Show Cause Order, among other things, stated that FERC would review the continued efficacy of Buckeye Pipe Line's unique program and directed Buckeye Pipe Line to show cause why it should not be required to discontinue the program on the Buckeye System and avail itself of the generic ratemaking methodologies used by other oil pipelines. The Show Cause Order also disallowed proposed rate increases on the Buckeye System that would have become effective April 1, 2012. The Show Cause Order did not impact any of the pipeline systems or terminals owned by Buckeye's other operating subsidiaries. On April 23, 2012, Buckeye Pipe Line requested rehearing as to the disallowance of certain rates. On February 22, 2013, FERC issued an order in Dkt. No. IS12-185 discontinuing Buckeye Pipe Line's unique program, and affirming on rehearing its rejection of all rate increases filed in March 2012 . The Ratemaking Methodology Order permitted Buckeye to retain its currently-filed rates in place, to make future rate changes in under market-based ratemaking authority in markets previously found to be competitive by FERC, and to make future changes in rates in other markets pursuant to the generic FERC ratemaking methods, which would include indexing. Pending finality of this order, the timing or outcome of final resolution of this matter cannot reasonably be determined at this time.

FERC Docket No. OR12-28 – Airlines Complaint against Buckeye Pipe Line New York City Jet Fuel Rates. On September 20, 2012, a complaint was filed with FERC by Delta Air Lines, JetBlue Airways, United/Continental Air Lines, and US Airways challenging Buckeye Pipe Line's rates for transportation of jet fuel from New Jersey to three New York City airports. The complaint was not directed at Buckeye Pipe Line's rates for service to other destinations, and does not involve pipeline systems and terminals owned by Buckeye's other operating subsidiaries. The complaint challenges these jet fuel transportation rates as generating revenues in excess of costs and thus being "unjust and unreasonable" under the Interstate Commerce Act. On October 10, 2012, Buckeye Pipe Line filed its answer to the complaint, contending that the airlines' allegations are based on inappropriate adjustments to the pipeline's costs and revenues, and that, in any event, any revenue recovery by Buckeye Pipe Line in excess of costs would be irrelevant because Buckeye Pipe Line's rates are set under a FERC-approved program that ties rates to competitive levels. Buckeye Pipe Line also sought dismissal of the complaint to the extent it seeks to challenge the portion of Buckeye Pipe Line's rates that were deemed just and reasonable, or "grandfathered," under Section 1803 of the Energy Policy Act of 1992. Buckeye Pipe Line further contested the airlines' ability to seek relief as to past charges where the rates are lawful under Buckeye Pipe Line's FERC-approved rate program. On October 25, 2012, the complainants filed their answer to Buckeye Pipe Line's motion to dismiss and answer. On November 9, 2012, Buckeye Pipe Line filed a response addressing newly raised arguments in the complainants' October 25th answer. On February 22, 2013, FERC issued an order setting the airline complaint in Dkt. No. OR12-28-000 for hearing, but holding the hearing in abeyance and setting the dispute for settlement procedures before a settlement judge. If FERC were to find these challenged rates to be in excess of costs and not otherwise protected by law, it could order Buckeye Pipe Line to reduce these rates prospectively and could order repayment to the complaining airlines of any past charges found to be in excess of just and reasonable levels for up to two years prior to the filing date of the complaint. Buckeye Pipe Line intends to vigorously defend its rates and its existing rate program. The timing or outcome of final resolution of this matter cannot reasonably be determined at this time.

FERC Docket No. OR13-3 – Buckeye Pipe Line's Market-Based Rate Application. On October 15, 2012, Buckeye Pipe Line filed an application with FERC seeking authority to charge market-based rates for deliveries of refined petroleum products to the New York City-area market (the "Application"). In the Application, Buckeye Pipe Line seeks to charge market-based rates from its three origin points in northeastern New Jersey to its five destinations on its Long Island System, including deliveries of jet fuel to the Newark, LaGuardia, and JFK airports. The jet fuel rates were also the subject of the airlines' OR12-28 complaint discussed above. On December 14, 2012, Delta Air Lines, JetBlue Airways, United/Continental Air Lines, and US Airways filed a joint intervention and protest challenging the Application and requesting its rejection. On January 14, 2013, Buckeye Pipe Line filed its answer to the protest and requested summary disposition as to those non-jet-fuel rates that were not challenged in the protest. On January 29, 2013, the protestants responded to Buckeye Pipe Line's answer. In addressing the Application, FERC will determine whether to approve the Application, deny it, or set it for further proceedings, including potentially an evidentiary hearing. If FERC were to approve the Application, Buckeye Pipe Line would be permitted prospectively to set these rates in response to competitive forces, and the basis for the airlines' claim for relief in their OR12-28 complaint as to Buckeye Pipe Line's future rates would be irrelevant prospectively. The timing or outcome of FERC's review of the Application cannot reasonably be determined at this time.

Environmental Proceedings

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 contested portions of the proposed penalty and in October 2012 we received a final order from PHMSA with respect to the matter and paid a penalty of $0.1 million.

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 contested the proposed penalty and in November 2012 PHMSA issued a final order with a reduced penalty of approximately $0.4 million. We filed a petition for reconsideration appealing this order. The timing or outcome of this appeal cannot reasonably be determined at this time.

Item 4. ***Mine Safety Disclosures***

Not applicable.

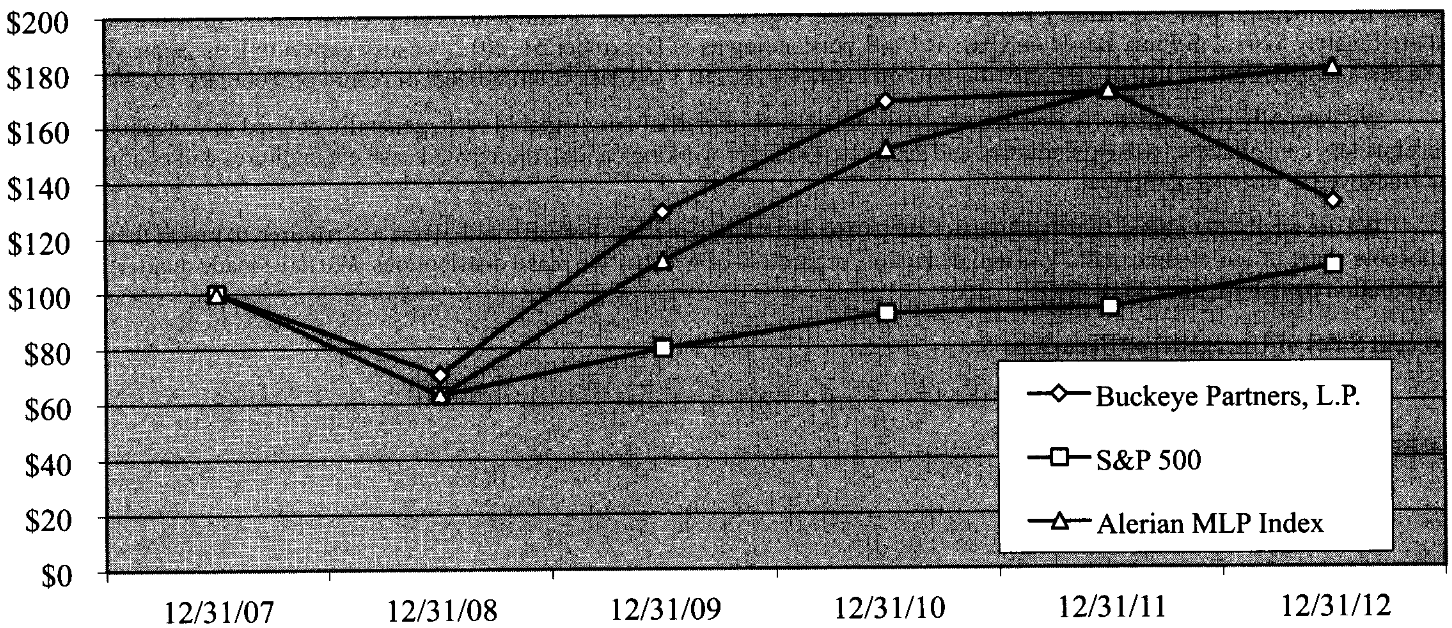
PART II

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, 2012 and 2011, as reported in the NYSE Composite Transactions, were as follows:

	2012		2011	
Quarter	High	Low	High	Low
First	$ 64.95	$ 58.50	$ 68.81	$ 58.45
Second	61.37	44.55	65.20	59.85
Third	54.68	47.06	65.24	54.51
Fourth	50.91	44.37	68.45	59.00

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 31, 2007 and that all distributions or dividends were reinvested on a quarterly basis.



	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011	12/31/2012
Buckeye Partners, L.P.	$ 100.00	$ 70.55	$ 128.99	$ 168.50	$ 171.74	$ 131.89
S&P 500	100.00	63.00	79.68	91.68	93.61	108.59
Alerian MLP Index	100.00	63.08	111.29	151.19	172.17	180.43

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 151,000 at December 31, 2012.

There is no established trading market for our Class B Units. As of December 31, 2012, our Class B Units were held by 9 holders of record.

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

Record Date	Payment Date		Amount Per LP Unit
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
February 21, 2012	February 29, 2012	$	1.0375
May 14, 2012	May 31, 2012		1.0375
August 15, 2012	August 31, 2012		1.0375
November 12, 2012	November 30, 2012		1.0375

On February 8, 2013, we announced a quarterly distribution of $1.0375 per LP Unit that will be paid on February 28, 2013, to unitholders of record on February 19, 2013. Based on the LP Units outstanding as of December 31, 2012 and the 6.9 million LP units issued in connection with our January 2013 equity offering, cash distributed to LP unitholders on February 28, 2013 will total approximately $101.2 million. Based on Class B Units outstanding as of December 31, 2012, we also expect to issue approximately 186,000 Class B Units in lieu of cash distributions on February 28, 2013 to Class B unitholders of record on February 19, 2013.

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.

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 present our selected consolidated financial data from our audited consolidated financial statements for the periods and at the dates indicated. The tables should be read in conjunction with our consolidated financial statements and our accompanying notes thereto included in Item 8 of this Report (in thousands, except per unit amounts).

	Year Ended December 31,				
	2012	2011 (1)	2010 (2)	2009 (2)	2008 (2)
Income Statement Data:					
Revenue	$ 4,357,242	$ 4,759,610	$ 3,151,268	$ 1,770,372	$ 1,896,652
Operating income (3)	339,208	188,682	278,582	203,457	247,293
Net income (3)	230,551	114,664	201,008	141,637	180,623
Net income attributable to Buckeye Partners, L.P. (3) (4)	226,417	108,501	43,080	49,594	26,477
Earnings per unit—diluted (5)	$ 2.32	$ 1.20	$ 1.65	$ 2.49	$ 1.33
Cash distributions per LP Unit—declared	$ 4.15	$ 4.03	$ 3.83	$ 3.63	$ 3.43

	December 31,				
	2012	2011	2010	2009	2008
Balance Sheet Data:					
Total assets	$ 5,981,009	$ 5,570,376	$ 3,574,216	$ 3,486,571	$ 3,263,097
Long-term debt	2,735,244	2,393,574	1,519,393	1,500,495	1,445,722
Total Buckeye Partners, L.P. capital (4)	2,372,313	2,303,169	1,392,405	242,334	232,060

(1) During the first quarter of 2011, we acquired a marine terminal in The Bahamas (see Note 3 in the Notes to Consolidated Financial Statements).

(2) 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. The exchange of BGH's units for our LP Units was accounted for as a BGH equity issuance, and pursuant to the Merger Agreement, Merger Sub was merged into BGH, with BGH as the surviving entity (the "Merger") for accounting purposes. The financial information for the periods prior to the effective date of the Merger is that of BGH. Although Buckeye is the surviving entity for legal purposes, BGH is the surviving entity for accounting purposes. Because BGH controlled Buckeye prior to the Merger, Buckeye's financial statements were consolidated into BGH.

(3) During 2012, 2011, 2010 and 2009, we recorded a $60.0 million asset impairment (see Note 7 in the Notes to Consolidated Financial Statements), a $169.6 million goodwill impairment (see Note 9 in the Notes to Consolidated Financial Statements), a $21.1 million modification of an equity compensation plan (see Note 18 in the Notes to Consolidated Financial Statements), and a $59.7 million asset impairment and $32.1 million reorganization expense, respectively.

(4) Prior to the Merger, BGH's noncontrolling interests primarily related to equity interests of Buckeye that were not owned by BGH. In connection with the Merger, total Buckeye capital substantially increased with the elimination of such noncontrolling interests.

(5) In connection with the Merger, the incentive compensation agreement (also referred to as the incentive distribution rights) held by our general partner was cancelled, and 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. Additionally, pursuant to the Merger, BGH's unitholders received a total of approximately 20.0 million of Buckeye's LP Units 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.

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.

Business Overview

We own and operate one of the largest independent refined petroleum products pipeline systems in the United States in terms of volumes delivered, miles of pipeline, and active product terminals. In addition, we operate and/or maintain 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 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 24 in the Notes to Consolidated Financial Statements for a more detailed discussion of our business segments.

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.

Overview of Operating Results

Net income attributable to our unitholders was $226.4 million for the year ended December 31, 2012, which was an increase of $117.9 million, or 109% from $108.5 million for the corresponding period in 2011. Operating income was $339.2 million for the year ended December 31, 2012, which is an increase of $150.5 million, or 80% from $188.7 million for the corresponding period in 2011.

Revenues for our Pipelines & Terminals segment grew significantly in 2012, primarily from the impact of recent acquisitions, including the assets acquired from BP and ExxonMobil in mid-2011 and the Perth Amboy Facility acquired in the second half of 2012. Pipeline transportation volumes on assets owned prior to the 2011 and 2012 acquisitions (which we refer to as our "legacy assets") declined marginally year-over-year driven by a decline in distillate volumes, primarily due to a warmer than usual winter in early 2012 resulting in lower heating oil movements. Throughput volumes for 2012 at terminals owned prior to the 2011 acquisitions (which we refer to as our "legacy terminals") increased over 2011 as our Chicago Complex benefited from record output at Midwest refineries and as recent growth capital projects became operational, including the transformation of our Albany terminal to add the ability to provide crude oil service. In addition, we purchased an additional 20% interest in WesPac Memphis from Kealine LLC. In January 2013, we ceased operations on a portion of Buckeye's NORCO pipeline system, consisting of approximately 169 miles of refined petroleum products pipelines and related assets in Indiana and Illinois. We recorded a non-cash impairment charge in the fourth quarter of 2012 of $60.0 million, which included $12.1 million of estimated costs associated with the removal and decommissioning of the pipeline.

Our International Operations segment benefited from the incremental contribution from the 1.9 million barrels of expansion capacity at BORCO that was completed in the second half of 2012. In addition to the storage revenue contribution from the expansion capacity, higher ancillary revenues, including berthing and heating revenues, were generated due to increased customer utilization of our facilities. Segment revenue also increased as a result of the launch of our fuel oil marketing business at the Yabucoa marine terminal, which is a low-margin business. We supply fuel oil under back-to-back arrangements that are intended to eliminate commodity and basis risks. In 2011, the International Operations segment was adversely impacted by lower than expected berthing revenue due to reductions in availability of fuel oil blending components as a result of operational issues at a refinery in the U.S. Virgin Islands ("Caribbean refinery") and lower vessel traffic as inventory optimization opportunities were limited by market conditions. These market conditions continued into 2012, resulting in weakness in demand for product storage in early 2012.

In 2012, our Natural Gas Storage segment improved over 2011 results, but unfavorable market conditions, including low natural gas prices, compressed seasonal spreads and low volatility, continued to negatively impact the segment's performance.

The Energy Services segment continued to be negatively impacted by extreme price volatility and basis risk, combined with market backwardation, in the markets it serves. We saw the benefits of the execution of our risk mitigation strategy, particularly in the second half of 2012, which included focusing on fewer, more strategic locations in which to transact business, better managing our inventories and reducing the cost structure of the business. Sales volumes declined as we executed this risk mitigation strategy. Our marketing operations remain a catalyst for incremental utilization of our Pipelines & Terminals assets as the contribution from Energy Services has been greater than its standalone reported results.

The liquefied petroleum gas ("LPG") storage caverns acquired in 2011 were a key contributor to growth for our Development & Logistics segment. In addition, we benefited from improved margins and new contract operations opportunities for our third-party engineering and operations business.

See the "Results of Operations" section below for further discussion and analysis of our operating segments.

Results of Operations

Consolidated Summary

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

	Year Ended December 31,		
	2012	2011	2010
Revenue	$ 4,357,242	$ 4,759,610	$ 3,151,268
Costs and expenses	4,018,034	4,570,928	2,872,686
Operating income	339,208	188,682	278,582
Earnings from equity investments	6,100	10,434	11,363
Gain on sale of equity investment	—	34,727	—
Interest and debt expense	(114,980)	(119,561)	(89,169)
Other income (expense)	(452)	190	(687)
Income before taxes	229,876	114,472	200,089
Income tax benefit	(675)	(192)	(919)
Net income	230,551	114,664	201,008
Less: Net income attributable to noncontrolling interests	(4,134)	(6,163)	(157,928)
Net income attributable to Buckeye Partners, L.P. (1)	$ 226,417	$ 108,501	$ 43,080
Earnings per unit—diluted (2)	$ 2.32	$ 1.20	$ 1.65

(1) Prior to the Merger, BGH's noncontrolling interests primarily related to equity interests of Buckeye that were not owned by BGH. In connection with the Merger, total Buckeye capital substantially increased with the elimination of such non-controlling interest.

(2) Pursuant to the Merger, BGH's unitholders received a total of approximately 20.0 million of Buckeye's LP Units 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.

Non-GAAP Financial Measures

Adjusted EBITDA is the primary measure used by our senior management, including our Chief Executive Officer, to: (i) evaluate our consolidated operating performance and the operating performance of our business segments; (ii) allocate resources and capital to business segments; (iii) evaluate the viability of proposed projects; and (iv) determine overall rates of return on alternative investment opportunities. Distributable cash flow is another measure used by our senior management to provide a clearer picture of cash available for distribution to its unitholders. Adjusted EBITDA and distributable cash flow eliminate (i) non-cash expenses, including but not limited to, depreciation and amortization expense resulting from the significant capital investments we make in our businesses and from intangible assets recognized in business combinations; (ii) charges for obligations expected to be settled with the issuance of equity instruments; and (iii) items that are not indicative of our core operating performance results and business outlook.

We believe that investors benefit from having access to the same financial measures that we use and that these measures are useful to investors because they aid in comparing our operating performance with that of other companies with similar operations. The Adjusted EBITDA and distributable cash flow data presented by us may not be comparable to similarly titled measures at other companies because these items may be defined differently by other companies.

The following table presents Adjusted EBITDA by segment and on a consolidated basis, distributable cash flow and a reconciliation of net income, which is the most comparable financial measure under generally accepted accounting principles ("GAAP"), to Adjusted EBITDA and distributable cash flow for the periods indicated (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Adjusted EBITDA:			
Pipelines & Terminals	$ 409,055	$ 361,018	$ 346,447
International Operations	132,104	112,996	(4,655)
Natural Gas Storage	6,118	4,204	29,794
Energy Services	524	1,797	5,861
Development & Logistics	11,722	7,932	5,193
Total Adjusted EBITDA	$ 559,523	$ 487,947	$ 382,640
Reconciliation of Net Income to Adjusted EBITDA and Distributable Cash Flow:			
Net income	$ 230,551	$ 114,664	$ 201,008
Less: Net income attributable to non-controlling interests	(4,134)	(6,163)	(157,928)
Net income attributable to Buckeye Partners, L.P.	226,417	108,501	43,080
Add: Interest and debt expense	114,980	119,561	89,169
Income tax expense	(675)	(192)	(919)
Depreciation and amortization	146,424	119,534	59,590
Non-cash deferred lease expense	3,901	4,122	4,235
Non-cash unit-based compensation expense	19,520	9,150	8,960
Asset impairment expense	59,950	—	—
Goodwill impairment expense	—	169,560	—
Equity plan modification expense	—	—	21,058
Net income attributable to non-controlling interests affected by Merger (1)	—	—	157,467
Less: Amortization of unfavorable storage contracts (2)	(10,994)	(7,562)	—
Gain on sale of equity investment	—	(34,727)	—
Adjusted EBITDA	559,523	487,947	382,640
Less: Interest and debt expense, excluding amortization of deferred financing costs and debt discounts	(111,511)	(111,941)	(84,758)
Income tax expense, excluding non-cash taxes	(1,095)	(6)	—
Maintenance capital expenditures	(54,425)	(57,467)	(31,244)
Distributable cash flow	$ 392,492	$ 318,533	$ 266,638

(1) Amounts represent portions of BGH's non-controlling 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 for comparability purposes.

(2) Represents the amortization of the negative fair values allocated to certain unfavorable storage contracts acquired in connection with the BORCO acquisition.

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,		
	2012	2011	2010
Pipelines & Terminals (average bpd in thousands):			
Pipelines:			
Gasoline	701.9	668.1	653.5
Jet fuel	339.2	340.6	338.5
Middle distillates (1)	322.3	327.2	303.4
Other products (2)	22.2	22.2	21.0
Total pipelines throughput	1,385.6	1,358.1	1,316.4
Terminals:			
Products throughput (3)	897.3	730.9	562.5
Energy Services (in millions of gallons):			
Sales volumes	1,106.3	1,337.8	1,139.1

(1) Includes diesel fuel, heating oil and kerosene.
(2) Includes liquefied petroleum gas.
(3) Amounts for 2012 and 2011 include throughput volumes at terminals acquired from BP and ExxonMobil Corporation on June 1, 2011 and July 19, 2011, respectively.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Consolidated

Adjusted EBITDA was $559.5 million for the year ended December 31, 2012, which is an increase of $71.6 million, or 14.7%, from $487.9 million for the corresponding period in 2011. The increase in Adjusted EBITDA was primarily related to positive contribution as a result of a full period of operating activities for 2011 acquisitions, the benefit of contributions from growth capital spending and higher blending capabilities, particularly butane blending, in the Pipelines & Terminals segment, as well as increased storage capacity and customer utilization of our BORCO facility in the International Operations segment.

Revenue was $4,357.2 million for the year ended December 31, 2012, which is a decrease of $402.4 million, or 8.5%, from $4,759.6 million for the corresponding period in 2011. The decrease in revenue was primarily related to a net decrease in revenue in the Energy Services segment, which was partially offset by the revenue generated due to a full period of operations for the 2011 acquisitions and the Perth Amboy Facility acquisition in 2012 in the Pipelines & Terminals segment, as well as increased storage revenue as a result of 1.9 million barrels of incremental storage capacity brought online and new service offerings providing fuel oil supply and distribution services in the International Operations segment.

Operating income was $339.2 million for the year ended December 31, 2012, which is an increase of $150.5 million, or 80.0%, from $188.7 million the corresponding period in 2011. The increase in operating income was primarily related to a non-cash goodwill impairment charge in the Natural Gas Storage segment in 2011 and positive contribution as a result of a full period of operating activities for 2011 acquisitions in the Pipelines & Terminals segment. These increases were partially offset by a non-cash asset impairment charge in 2012 and an increase in depreciation and amortization due to the assets acquired in 2011 in the Pipelines & Terminals segment and the upgrades and expansions of the jetty structure in the International Operations segment.

Distributable cash flow was $392.5 million for the year ended December 31, 2012, which is an increase of $74.0 million, or 23.2%, from $318.5 million for the corresponding period in 2011. The increase in distributable cash flow was primarily related to an increase of $71.6 million in Adjusted EBITDA as described above.

Adjusted EBITDA by Segment

Pipelines & Terminals. Adjusted EBITDA from the Pipelines & Terminals segment was $409.1 million for the year ended December 31, 2012, which was an increase of $48.1 million, or 13.3%, from $361.0 million for the corresponding period in 2011. The positive factors impacting Adjusted EBITDA were related to a $44.2 million increase in revenue due to a full period of operations for the assets acquired in 2011 and the Perth Amboy Facility acquired in 2012, a $31.7 million increase in revenue due to higher average pipeline tariff rates, resulting from tariff increases and long-haul shipments, and terminalling contract rate escalations on our legacy assets, $11.1 million of favorable settlement experience, a $7.9 million increase in revenue due to higher blending capabilities in the Northeast, particularly butane blending, and a $1.6 million increase in revenue due to higher terminalling volumes. The favorable settlement experience primarily related to the successful resolution of a $10.6 million product settlement allocation matter related to certain pipeline transportation-related services provided by Buckeye over a period of several years, of which $7.8 million related to services rendered in prior years but, for accounting purposes, was not recognized in revenue until the current period.

The negative factors impacting Adjusted EBITDA were a $17.1 million increase in operating expenses related to a full period of operations of the assets acquired in 2011 and the Perth Amboy Facility acquired in 2012, which included acquisition and transition expenses, a $9.5 million increase in operating expenses, which included integrity program expenditures, payroll costs, operating power and utilities, insurance and environmental remediation expenses, a $8.5 million decrease in other revenue, resulting from a decrease in terminalling storage contracts primarily due to market backwardation of refined petroleum products, a $4.3 million decrease in earnings from equity investments primarily due to higher environmental remediation costs at West Shore and the sale of our interest in West Texas LPG Pipeline Limited Partnership in 2011, $3.8 million in fees related to the FERC proceedings, $1.5 million of fees related to the temporary suspension of ethanol offloading capabilities at our Albany facility and a $3.7 million increase in expenses related to the relocation of certain operations and administrative support functions to our Houston, Texas headquarters.

Overall pipeline and terminalling volumes increased by 2.0% and 22.8%, respectively, primarily as a result of the assets acquired in 2011. Legacy pipeline volumes declined marginally as a result of seasonal fluctuations in heating oil, a temporary shut-down of one of our pipelines for emergency maintenance, and business interruptions caused by Hurricane Sandy, offset by higher demand for gasoline. Legacy terminalling volumes increased by 1.6% due to higher demand for gasoline and distillates, new customer contracts and service offerings at select locations, including crude oil services and the benefit of contributions from growth capital spending.

International Operations. Adjusted EBITDA from the International Operations segment was $132.1 million for the year ended December 31, 2012, which was an increase of $19.1 million, or 16.9%, from $113.0 million for the corresponding period in 2011. The positive factors impacting Adjusted EBITDA were primarily related to a $46.0 million increase in revenue related to new service offerings providing fuel oil supply and distribution services in the Caribbean, a $7.9 million decrease in acquisition and transition expenses, a $6.0 million increase in storage revenue as a result of 1.9 million barrels of incremental storage capacity brought online, a $5.0 million increase in ancillary revenues, including berthing, which represents ships that utilize the jetties, and heating services due to increased customer utilization of our facilities and $1.7 million decrease in income allocated to non-controlling interests related to the remaining 20% ownership interest in BORCO not acquired by us until February 16, 2011.

The increase in revenue was partially offset by a $45.5 million increase in cost of product sales related to new service offerings providing fuel oil supply and distribution services in the Caribbean and $2.0 million increase in operating expenses primarily as a result of increased customer utilization of our facilities.

Natural Gas Storage. Adjusted EBITDA from the Natural Gas Storage segment was $6.1 million for the year ended December 31, 2012, which was an increase of $1.9 million, or 45.5%, from $4.2 million for the corresponding period in 2011. The increase in Adjusted EBITDA was primarily the result of an $18.1 million increase in fees for hub service activities due to improved seasonal spreads and a $1.0 million decrease in operating expenses, which primarily related to a decline in the number of well workovers performed during 2012 as compared to the 2011 period. The increase in Adjusted EBITDA was partially offset by a $12.8 million decrease in lease revenue due to lower firm storage rates and a $4.4 million increase in costs of natural gas storage services, which includes hub services fees paid to customers for hub service activities. Lease revenue and hub services revenue are affected 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).

Energy Services. Adjusted EBITDA from the Energy Services segment was $0.5 million for the year ended December 31, 2012, which was a decrease of $1.3 million, or 70.8%, from $1.8 million for the corresponding period in 2011. In early 2012, we developed and executed a strategy to mitigate basis risk, which included the reduction of refined petroleum product inventories in the Midwest. As a result, losses generated from the execution of our strategy contributed to the decrease in Adjusted EBITDA. During the period, we continued to aggressively manage our inventory levels and reduce our exposure to market backwardation, despite sustained adverse market conditions. In addition, we had a $2.2 million decrease in biodiesel tax credits, which are recorded as a reduction of cost of sales. In early 2013, legislative changes resulted in retroactive recognition of biodiesel tax credits for year 2012.

The decrease in Adjusted EBITDA was primarily related to a $595.7 million net decrease in revenue, which included a $673.0 million decrease due to 17.3% of lower sales volumes, offset by a $77.3 million increase as a result of approximately $0.07 per gallon increase in refined petroleum product sales price (average sales prices per gallon were $2.98 and $2.91 for the 2012 and 2011 periods, respectively).

The decrease in revenue was partially offset by a $592.0 million net decrease in cost of product sales, which included a $670.0 million decrease due to 17.3% of lower sales volumes, offset by $78.0 million increase as a result of approximately $0.07 per gallon increase in refined petroleum product cost price (average cost prices per gallon were $2.96 and $2.89 for the 2012 and 2011 periods, respectively) and a $2.4 million decrease in operating expenses primarily related to overhead costs.

Development & Logistics. Adjusted EBITDA from the Development & Logistics segment was $11.7 million for the year ended December 31, 2012, which was an increase of $3.8 million, or 47.8%, from $7.9 million for the corresponding period in 2011. The increase in Adjusted EBITDA was primarily due to a $4.5 million increase in revenue related to the LPG storage caverns acquired in November 2011, a $2.6 million increase in third-party engineering and operations revenue as a result of new contracts and higher fees, partially offset by a $1.9 million increase in operating expenses, which primarily related to overhead costs, a $0.8 million increase in third-party engineering and operations expense and a $0.6 million increase in operating expenses for the LPG storage caverns.

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

Consolidated

Adjusted EBITDA was $487.9 million for the year ended December 31, 2011, which is an increase of $105.3 million, or 27.5%, from $382.6 million for the corresponding period in 2010. The increase in Adjusted EBITDA was primarily related to positive contribution as a result of the 2011 acquisitions in the Pipelines & Terminals segment and International Operations segment's acquisition of the BORCO facility in 2011 and a full year of operations for the Yabucoa terminal, which was acquired in December 2010. These increases were partially offset by decreased earnings in the Natural Gas Storage segment as a result of low volatility in natural gas prices and compressed seasonal spreads in part due to system capacity constraints.

Revenue was $4,759.6 million for the year ended December 31, 2011, which was an increase of $1,608.3 million, or 51.0%, from $3,151.3 million for the corresponding period in 2010. The increase in revenue was primarily related to the increase in revenue in the Energy Services segment, as well as the increase in revenue as a result of the assets acquired in 2011 in the Pipelines & Terminals and International Operations segments. These increases in revenue were partially offset by the decrease in revenue in the Natural Gas Storage segment primarily related to a reduced level of hub services activities caused by the weakness in market fundamentals.

Operating income was $188.7 million for the year ended December 31, 2011, which was a decrease of $89.9 million, or 32.3%, from $278.6 million for the corresponding period in 2010. The decrease in operating income was primarily related to a non-cash goodwill impairment charge in the Natural Gas Storage segment and an increase in depreciation and amortization due to assets acquired in 2011 in the Pipelines & Terminals and International Operations segment, which was partially offset by positive contribution as a result of the assets acquired in 2011 in the Pipelines & Terminals segment and International Operations segment and a decrease in compensation expense as a result of the equity plan modification expense during 2010.

Distributable cash flow was $318.5 million for the year ended December 31, 2011, which was an increase of $51.9 million, or 19.5%, from $266.6 million for the corresponding period in 2010. The increase in distributable cash flow was primarily related to an increase of $105.3 million in Adjusted EBITDA as described above, partially offset by a $26.2 million increase in maintenance capital expenditures relating to pipeline and tank integrity work performed in the Pipelines & Terminals and International Operations segments.

Adjusted EBITDA by Segment

Pipelines & Terminals. Adjusted EBITDA from the Pipelines & Terminals segment was $361.0 million for the year ended December 31, 2011, which was an increase of $14.6 million, or 4.2%, from $346.4 million for the corresponding period in 2010. The positive factors impacting Adjusted EBITDA were related to a $48.5 million increase in revenue 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 in Adjusted EBITDA were partially offset by a $25.7 million increase in operating costs relating to pipeline and terminal acquisitions in 2011, 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, which included environmental remediation expenses, property taxes and payroll costs, $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.

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.

International Operations. Adjusted EBITDA from the International Operations segment was $113.0 million for the year ended December 31, 2011, which was an increase of $117.7 million from a loss of $4.7 million for the corresponding period in 2010. The positive factors impacting Adjusted EBITDA were primarily related to the BORCO acquisition in 2011 and a full year of operations for the Yabucoa terminal. The increase in Adjusted EBITDA was primarily due to a $151.0 million increase in storage revenue and $34.5 million in ancillary revenues, including berthing and heating services, partially offset by $62.9 million in operating costs, which included payroll costs, repair costs, insurance expenses, lease expenses and other costs, a $3.2 million increase in acquisition and integration expenses and $1.7 million increase in income allocated to non-controlling interests related to the remaining 20% ownership interest in BORCO not acquired by us until February 16, 2011.

Natural Gas Storage. Adjusted EBITDA from the Natural Gas Storage segment was $4.2 million for the year ended December 31, 2011, which was a decrease of $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 $20.7 million and $8.6 million decrease in hub services activities and 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 $3.0 million of higher operating costs, partially offset by a $6.7 million decrease in cost of natural gas storage services.

Energy Services. Adjusted EBITDA from the Energy Services segment was $1.8 million for the year ended December 31, 2011, which was a decrease of $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 impacted the flow of product along the supply chain and warmer weather conditions, which resulted in decreased consumer demand, created downward pressure on basis.

The decrease in Adjusted EBITDA was primarily related to a $1,413.2 million increase in cost of product sales, which included a $428.8 million increase due to 17.4% of higher sales volumes and a $984.4 million increase as a result of approximately $0.73 per gallon increase in refined petroleum product cost price (average cost prices per gallon were $2.89 and $2.16 for the 2011 and 2010 periods, respectively).

The increase in cost of product sales was partially offset by a $1,407.4 million increase in revenue, which included a $432.9 million increase due to 17.4% of higher sales volumes and a $974.5 million increase as a result of approximately $0.73 per gallon increase in refined petroleum product sales price (average sales prices per gallon were $2.91 and $2.18 for the 2011 and 2010 periods, respectively) and a $1.7 million decrease in operating expenses primarily related to overhead costs.

Development & Logistics. Adjusted EBITDA from the Development & Logistics segment was $7.9 million for the year ended December 31, 2011, which was an increase of $2.7 million, or 52.7%, from $5.2 million for the corresponding period in 2010. The increase in Adjusted EBITDA was primarily due to a $5.5 million increase in third-party engineering and operations revenue as a result of new contracts and higher fees, $2.4 million in expenses associated with a customer bankruptcy in the 2010 period and $0.7 million of revenue relating to the LPG storage caverns acquired in November 2011, partially offset by a $3.7 million increase in third-party engineering and operations expenses, $1.3 million of higher operating and other costs and $0.9 million of net proceeds from the ammonia line fill sale in the 2010 period.

General Outlook for 2013

For our Pipelines & Terminals segment, we do not expect any significant change in macro-economic demand for petroleum products in the markets we serve in 2013 absent a significant change in the economy. We expect that throughput volumes on our pipeline systems will experience moderate growth, primarily as a result of what we expect to be a normal winter in terms of average temperature, which should allow for the rebound of heating oil volumes as compared to the relatively warm winter weather in early 2012. Our pipeline revenues are expected to benefit from increased tariffs on our indexed system, but some uncertainty remains related to the ways in which FERC's February 22, 2013 Ratemaking Methodology Order issued in Dkt. No. IS12-185-000 *et al.*, discussed above, will affect future changes to Buckeye's rates in markets outside the New York City market. In addition, the ultimate resolution of the complaint of certain airlines regarding jet fuel rates to the three major New York City area airports in Dkt. No. OR12-28-000 could impact rates to those destinations. Base throughput volumes at our terminal assets are expected to remain flat, with moderate volume growth expected from return capital projects, such as the modernization of our Perth Amboy facility, transformation of our Albany facility to allow for crude service, expansion of our Chicago Complex, and completion of propylene off-take storage in the Midwest. Additionally, we are exploring opportunities to leverage our assets to provide crude supply logistic solutions as domestic shale plays continue to change the crude supply landscape. Ultimately, our ability to increase transportation and storage revenues is largely dependent on the strength of the overall economy in the markets we serve.

Looking forward to 2013 for our International Operations segment, we expect to place in-service an additional 2.8 million barrels of expansion storage capacity, including 1.2 million barrels of crude storage. We have seen increased demand for crude storage in the Caribbean as production off the coast of South America begins to ramp up. BORCO has the capability to function as a staging and blending facility in the logistics chain for producers as they move crude production to refining centers. We expect moderate increases in storage service rates prospectively and expect BORCO to be fully leased for 2013, except for required maintenance work. Our ability to achieve higher rates and increase storage utilization is ultimately dependent on the global product demand in the markets we serve. We enjoyed the initial contribution in late 2012 from our fuel oil business at our Yabucoa terminal, where we secure supply for Caribbean utility plants, and expect the contribution from that business to grow in 2013. 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.

We expect our Natural Gas Storage segment will continue to be challenged in 2013 as we do not expect any significant improvement in market fundamentals.

We expect Energy Services performance will improve in 2013 as it continues to execute on our risk mitigation strategy which benefited the segment in the second half of 2012. We do not expect a significant improvement in market fundamentals. We believe, however, that the Energy Services segment will continue to be a significant contributor in utilization of pipeline and terminal assets.

Our Development & Logistics segment has a robust pipeline of potential projects that we expect will continue its growth.

In the first quarter of 2013, we accessed the equity market and used the net proceeds to pay down existing indebtedness, which essentially was a pre-funding of our anticipated 2013 growth capital spend. We believe that, under current market conditions, we could raise additional capital in both the debt and equity markets on acceptable terms.

Throughout 2013, 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 2013" 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 2013" may not occur.

Liquidity and Capital Resources

General

Our primary cash requirements, in addition to normal operating expenses and debt service, are for working capital, capital expenditures, business acquisitions and distributions to partners. Our principal sources of liquidity are cash from operations, borrowings under our Credit Facility and proceeds from the issuance of our units. We will, from time to time, issue debt securities to permanently finance amounts borrowed under our Credit 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 maintenance capital expenditures with cash from operations. Expansion and cost reduction capital expenditures, along with acquisitions, have typically been funded from external sources including our 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. Based on current market conditions, we believe our borrowing capacity under our Credit Facility, cash flows from operations and access to debt and equity markets, if necessary, will be sufficient to fund our primary cash requirements, including our expansion plans over the next 12 months.

Current Liquidity

As of December 31, 2012, we had $40.0 million of working capital and $378.8 million of additional borrowing capacity 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 on file with the SEC that currently has a $750.0 million limit on the amount of equity securities that we may issue thereunder. 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.

In addition, we periodically evaluate engaging in strategic transactions as a source of capital or may consider divesting non-core assets where such evaluation suggests such a transaction is in the best interest of Buckeye.

Debt

At December 31, 2012, we had the following debt obligations (in thousands):

4.625% Notes due July 15, 2013	$	300,000
5.300% Notes due October 15, 2014		275,000
5.125% Notes due July 1, 2017		125,000
6.050% Notes due January 15, 2018		300,000
5.500% Notes due August 15, 2019		275,000
4.875% Notes due February 1, 2021		650,000
6.750% Notes due August 15, 2033		150,000
BPL Credit Facility due September 26, 2016		871,200
Total debt	$	2,946,200

It is our intent to refinance the 4.625% Notes in 2013. If necessary, the $300.0 million of 4.625% Notes maturing on July 15, 2013 could be refinanced using our Credit Facility. At December 31, 2012, we had $378.8 million of additional borrowing capacity under our Credit Facility. Additionally, we expect to pay approximately $72.8 million to settle interest rate swaps relating to the refinancing of the 4.625% Notes on or before July 15, 2013.

Equity

In January 2013, we completed a public offering of 6,000,000 LP Units pursuant to an effective shelf registration statement, which priced at $52.54 per unit. The underwriters also exercised an option to purchase 900,000 additional LP Units, resulting in total gross proceeds of approximately $362.5 million before deducting underwriting fees and estimated offering expenses. We used the net proceeds from this offering to reduce the indebtedness outstanding under our revolving credit facility.

In 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 at a price of $58.65 per LP Unit, before deducting placement agents' fees and estimated offering expenses. We used the majority of the net proceeds from this offering to reduce the indebtedness outstanding under our Credit Facility and to indirectly fund a portion of the Perth Amboy Facility acquisition as well as certain other growth capital expenditures.

Capital Allocation

We continually review our investment options with respect to our capital resources that are not distributed to our unitholders or used to pay down our debt and we seek to invest this capital in various projects and activities based on their return to Buckeye. Potential investments could include, among others: add-on or other enhancement projects associated with our current assets; greenfield or brownfield development projects; and merger and acquisition activities.

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,		
	2012	2011	2010
Cash provided by (used in):			
Operating activities	$ 441,636	$ 403,892	$ 292,479
Investing activities	(590,322)	(1,310,279)	(114,188)
Financing activities	142,476	905,747	(202,239)

Operating Activities

2012 Compared to 2011. Net cash provided by operating activities was $441.6 million for the year ended December 31, 2012, which is an increase of $37.7 million, from $403.9 million for the corresponding period in 2011. The increase in cash provided by operating activities primarily related to an increase in income resulting from a full period of operations for the assets acquired in 2011, and the Perth Amboy Facility acquired in 2012 and a decrease in refined petroleum products inventory in 2012. In early 2012, we developed and executed a strategy to mitigate our basis risk that included the reduction of refined petroleum product inventories in the Midwest.

2011 Compared to 2010. Net cash provided by operating activities was $403.9 million for the year ended December 31, 2011, which is an increase of $111.4 million, from $292.5 million for the corresponding period in 2010. The increase in cash provided by operating activities primarily related to income resulting from the operations of the BORCO facility and pipeline and terminal assets acquired in 2011 and the Yabucoa terminal in 2010 and a cash inflow related to a decrease in refined petroleum products inventory in 2011, partially offset by an increase in interest and debt expense during 2011.

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 demand for our services, 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

2012. Net cash used in investing activities of $590.3 million for the year ended December 31, 2012 primarily related to $331.3 million of capital expenditures and a $260.3 million acquisition of the Perth Amboy Facility.

2011. Net cash used in investing activities of $1,310.3 million for the year ended December 31, 2011 primarily related to a $1.4 billion acquisition of BORCO, of which $893.7 million was paid in cash, net of cash acquired and the remaining consideration in issuance of LP Units and Class B Units, a $166.0 million acquisition of pipeline and terminal assets and $305.3 million of capital expenditures, which were partially offset by $85.0 million of cash proceeds from the sale of our 20% interest in West Texas LPG Pipeline Limited Partnership.

2010. Net cash used in investing activities of $114.2 million for the year ended December 31, 2010 primarily related to $77.7 million of capital expenditures and a $32.8 million acquisition of the Yabucoa terminal.

See below for a discussion of capital spending. For further discussion on our acquisitions, see Note 3 in the Notes to Consolidated Financial Statements.

We have capital expenditures, which we define as "maintenance capital expenditures," in order to maintain and enhance the safety and integrity of our pipelines, terminals, storage facilities and related assets, and "expansion and cost reduction capital expenditures" to expand the reach or capacity of those assets, to improve the efficiency of our operations and to pursue new business opportunities. 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,		
	2012	2011	2010
Maintenance capital expenditures	$ 54,425	$ 57,467	$ 31,244
Expansion and cost reduction	276,913	247,857	46,455
Total capital expenditures, net	$ 331,338	$ 305,324	$ 77,699

In 2012, maintenance capital expenditures included terminal pump replacements, truck rack infrastructure upgrades, as well as pipeline and tank integrity work, and 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, transformation of our Albany marine terminal to handle crude services via rail and ship, new natural gas storage wells, continued progress on a new pipeline and terminal billing system as well as various other operating infrastructure projects. In 2011 and 2010, maintenance capital expenditures included pipeline and tank integrity work, and 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, the construction of three additional tanks with capacity of 0.4 million barrels in Linden, New Jersey and various other pipeline and terminal operating infrastructure projects.

We estimate our capital expenditures for the period indicated as follows (in thousands):

	2013	
	Low	High
Pipelines & Terminals:		
Maintenance capital expenditures	$ 50,000	$ 60,000
Expansion and cost reduction	220,000	255,000
Total capital expenditures	$ 270,000	$ 315,000
International Operations:		
Maintenance capital expenditures	$ 10,000	$ 20,000
Expansion and cost reduction	80,000	105,000
Total capital expenditures	$ 90,000	$ 125,000
Overall:		
Maintenance capital expenditures	$ 60,000	$ 80,000
Expansion and cost reduction	300,000	360,000
Total capital expenditures	$ 360,000	$ 440,000

Estimated maintenance 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. Estimated major expansion and cost reduction expenditures include storage tank expansion projects at the BORCO facility, completion of additional storage tanks and rail loading facilities in the Midwest, truck loading rack upgrades in the Midwest, the refurbishment of storage tanks across our system, 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 butane blending business. In connection with the Perth Amboy Facility acquisition, our estimated expansion and cost reduction expenditures include refurbishment of the asphalt truck and rail rack, development of a new crude rail offloading system, completion of a bi-directional pipeline, conversion of tanks for distillate and gasoline storage, a new gasoline and diesel truck loading rack installation, construction of a multi-product blend and transfer piping manifold, and construction of a new 16- inch pipeline allowing direct access to our existing pipeline infrastructure. Also, estimated expansion and cost reduction expenditures include costs to repair the damaged jetty at our BORCO facility as a result of the allision of a vessel with our jetty in May 2012. We believe the recovery of the costs to repair the damaged jetty is probable. See Note 4 in the Notes to Consolidated Financial Statements for a more detailed discussion of this incident. Furthermore, cost reduction expenditures improve operational efficiencies or reduce costs.

Financing Activities

2012. Net cash flows provided by financing activities of $142.5 million for the year ended December 31, 2012 primarily related to $296.0 million of net borrowings under the Credit Facility and $246.8 million of net proceeds from the issuance of 4.3 million LP Units to reduce borrowings under our Credit Facility and fund a portion of the Perth Amboy Facility acquisition, partially offset by $371.2 million ($4.15 per LP Unit) of cash distributions paid to our unitholders.

2011. Net cash flows provided by financing activities of $905.7 million for the year ended December 31, 2011 primarily related to $736.9 million of net proceeds from the issuance of 11.3 million LP Units and 1.3 million Class B Units to fund a portion of the BORCO acquisition and reduce borrowings under our Credit Facility, $647.5 million from the issuance of the 4.875% Notes, and $192.9 million of net borrowings under the Credit Facility, partially offset by $335.7 million ($4.025 per LP Unit) of cash distributions paid to our unitholders and $318.2 million repayment of debt assumed and settlement of interest rate derivative instruments relating to the BORCO acquisition.

2010. Net cash flows used in financing activities of $202.2 million for the year ended December 31, 2010 primarily related to $195.6 million of cash distributions paid to noncontrolling partners of Buckeye, which consisted primarily of distribution to holders of LP Units ($3.825 per LP Unit).

For further discussion on our equity offerings, see Note 21 in the Notes to Consolidated Financial Statements.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2012 (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)	$ 2,740,000	$ 300,000	$ 275,000	$ 790,000	$ 1,375,000
Interest payments (2) (3)	834,832	134,496	236,442	182,605	281,289
Operating leases:					
Office space and other	29,745	3,238	7,161	7,560	11,786
Equipment (4)	5,701	3,608	2,093	—	—
Land leases (5)	407,217	5,763	11,813	12,368	377,273
Purchase obligations (6)	90,627	90,627	—	—	—
Capital expenditure obligations (7)	21,665	21,665	—	—	—
Total contractual obligations	$ 4,129,787	$ 559,397	$ 532,509	$ 992,533	$ 2,045,348

(1) Includes long-term debt portion borrowed by Buckeye under our Credit Facility. See Note 12 in the Notes to Consolidated Financial Statements for additional information regarding our debt obligations.

(2) Includes amounts due on our notes and amounts 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) Excludes estimates of the effect of our interest rate swaps related to forecasted interest payments. As of December 31, 2012, the fair value of our interest rate swaps of $ 72.8 million and $ 57.8 million are expected to be settled on or about July 15, 2013 and October 14, 2014, respectively.

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

(5) Includes leases for properties in connection with both the jetty and inland dock operations in the International Operations segment and leases for subsurface underground gas storage rights and surface rights in connection with our operations in the Natural Gas Storage segment. We may cancel 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 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.

(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.

For the year ended 2013, our rights-of-way payments are expected to be approximately $7.6 million, which includes an estimated amount for annual escalation.

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.

The ESOP was frozen with respect to benefits effective March 27, 2011 (the "Freeze Date"). No Services Company contributions have been or 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.

All Services Company stock has been allocated to ESOP participants. See Note 19 in the Notes to Consolidated Financial Statements for further information.

Off-Balance Sheet Arrangements

At December 31, 2012 and 2011, we had no off-balance sheet debt or arrangements.

Critical Accounting Policies and 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. Estimates and assumptions about future events and their effects cannot be made with certainty. Estimates may change as new events occur, when additional information becomes available and if the Partnership's operating environment changes. Actual results could differ from our estimates. See Note 2 in the Notes to Consolidated Financial Statements for our significant accounting policies. The following describes significant estimates and assumptions affecting the application of these policies:

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. 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 and operating expenses, (ii) long-term growth rates and (iii) an appropriate discount rate. 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.

For our annual goodwill impairment test as of January 1, 2013, 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 value. Based on our assessment, the Pipelines & Terminals reporting unit had (i) a substantial excess of fair value over carrying value in its latest quantitative assessment, (ii) continued positive performance in Adjusted EBITDA over prior year, (iii) projected increases in Adjusted EBITDA primarily as a result of contributions from internal capital projects, and (iv) positive industry and market factors. We determined that the fair value of the reporting unit exceeded the carrying amount; therefore, the two-step impairment test was not required.

Additionally, we performed quantitative assessments to determine the fair value of each of the remaining reporting units. 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 and operating expenses, (ii) long-term growth rates and (iii) an appropriate discount rate. 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. Based on such calculations, each reporting unit's fair value was in excess of its carrying value. We did not record any goodwill impairment charges during the year ended December 31, 2012. During the year ended December 31, 2011, we recorded a non-cash goodwill impairment charge of $169.6 million in the Natural Gas Storage segment. We did not record a goodwill impairment charge for the year ended December 31, 2010.

Our financial forecast for the International Operations reporting unit has assumptions relating to additional storage tank expansion associated with a potential increase in demand for crude oil. While we believe that a market participant would include the potential benefit of this expansion in its assessment of fair value, we performed a sensitivity analysis to remove the projected revenue relating to the additional storage tank expansion. An elimination of this projected revenue would not indicate an impairment; however, the excess fair value over carrying value would be minimal.

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. Estimates of undiscounted future cash flows include (i) discrete financial forecasts, which rely on management's estimates of revenue and operating expenses, (ii) long-term growth rates, and (iii) estimates of useful lives of the assets. Such estimates of future undiscounted cash flows are highly subjective and are based on numerous assumptions about future operations and market conditions.

During the fourth quarter of 2012, we recorded a $60.0 million non-cash asset impairment charge in the Pipelines & Terminals segment relating to a portion of Buckeye's NORCO pipeline system. During 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 the Natural Gas Storage assets for impairment and concluded that no impairment of the long-lived assets existed at that time. See Note 7 and 9 in the Notes to Consolidated Financial Statements for further discussion. There was not an asset impairment charge during 2010.

We evaluate equity method investments for impairment whenever events or changes in circumstances indicate that there is an "other than temporary" loss in value of the investment. Estimates of future cash flows include (i) discrete financial forecasts, which rely on management's estimates of revenue and operating expenses, (ii) long-term growth rates, and (iii) probabilities assigned to different cash flow scenarios. There were no impairments of our equity investments during the years ended December 31, 2012, 2011 or 2010.

Reserves for Environmental Matters

We record environmental liabilities at a specific site when environmental assessments occur or remediation efforts are probable, and the costs can be reasonably estimated based upon past experience, discussion with operating personnel, advice of outside engineering and consulting firms, discussion with legal counsel, or current facts and circumstances. The estimates related to environmental matters are uncertain because (i) estimated future expenditures are subject to cost fluctuations and change in estimated remediation period, (ii) unanticipated liabilities may arise, and (iii) changes in federal, state and local environmental laws and regulations may significantly change the extent of remediation.

Fair Value of Derivatives

We are exposed to financial market risks, including changes in interest rates and commodity prices, in the course of our normal business operations. We use derivative instruments to manage these risks.

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. The futures contracts used to hedge refined petroleum product inventories are designated as fair value hedges with changes in fair value of both the futures contracts and physical inventory reflected in earnings. Physical contracts and futures contracts that have not been designated in a hedge relationship are marked-to-market.

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.

Each customer is evaluated for performance under the terms and conditions of their contracts; therefore, we 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. When entering into interest rate swap transactions, we are exposed to both credit risk and market risk. We manage our credit risk by entering into swap transactions only 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. 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.

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 risks, including changes in commodity prices and interest rates. The primary factors affecting our market risk and the fair value of our derivative portfolio at any point in time are the volume of open derivative positions, changing refined petroleum commodity prices, and prevailing interest rates for our interest rate swaps. Since prices for refined petroleum products and interest rates are volatile, there may be material changes in the fair value of our derivatives over time, driven both by price volatility and the changes in volume of open derivative transactions.

The following is a summary of changes in fair value of our derivative instruments for the periods indicated (in thousands):

	Commodity Instruments	Interest Rate Swaps	Total
Fair value of contracts outstanding at January 1, 2012	$ 4,897	$ (101,911)	$ (97,014)
Items recognized or settled during the period	19,630	—	19,630
Fair value attributable to new deals	(14,846)	—	(14,846)
Change in fair value attributable to price movements	(18,144)	(28,725)	(46,869)
Change in fair value attributable to non-performance risk	24	—	24
Fair value of contracts outstanding at December 31, 2012	$ (8,439)	$ (130,636)	$ (139,075)

Commodity Price Risk

Natural Gas Storage

The Natural Gas Storage segment enters into interruptible natural gas storage hub service agreements in order to manage the operational integrity of the natural gas storage facility, while also attempting to capture value from seasonal price differences in the natural gas markets. Although the Natural Gas Storage segment does not purchase or sell natural gas, the Natural Gas Storage segment is subject to commodity risk because the value of natural gas storage hub services generally fluctuates based on changes in the relative market prices of natural gas over different delivery periods. The hub service agreements do not qualify as derivatives and therefore are not accounted for at fair value. The fee to be received or paid is based on the time spread at the time of execution. The hub service agreements are accrued as fees are paid or received and recognized ratably in earnings over the entire term of the transactions.

The following is a summary of changes in the net balance sheet of our outstanding hub service agreements (in thousands):

Net Asset at January 1, 2012	$ 11,390
Net revenue recognized in period (1)	5,586
Net unearned revenue (2)	(4,929)
Net Asset at December 31, 2012	$ 12,047

(1) Net revenue was amortized into earnings based on the net fee received for injection and withdrawal services performed during the period.

(2) Fees were collected and a net liability was recorded for injection and withdrawal services to be rendered in future periods.

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 derivative contracts. Based on a hypothetical 10% movement in the underlying quoted market prices of the futures contracts and observable market data from third-party pricing publications for physical derivative contracts related to designated hedged refined petroleum products inventories outstanding and physical derivative contracts at December 31, 2012, the estimated fair value would be as follows (in thousands):

Scenario	Resulting Classification	Fair Value
Fair value assuming no change in underlying commodity prices (as is)	Asset	$ 206,899
Fair value assuming 10% increase in underlying commodity prices	Asset	203,889
Fair value assuming 10% decrease in underlying commodity prices	Asset	209,909

Interest Rate Risk

We utilize forward-starting interest rate swaps to hedge the variability of the forecasted interest payments on anticipated debt issuances that may result from changes in the benchmark interest rate until the expected debt is issued. When entering into interest rate swap transactions, we are exposed to both credit risk and market risk. We manage our credit risk by entering into swap transactions only with major financial institutions with investment-grade credit ratings. 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 swaps. 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 swap agreements to manage our interest rate and cash flow risks associated with a credit facility. In addition, in July 2009 and May 2010, Buckeye GP's board of directors authorized us to enter into certain transactions, such as forward-starting interest rate swaps, to manage our interest rate and cash flow risks related to certain expected debt issuances associated with the maturity of existing debt obligations.

Based on a hypothetical 10% movement in the underlying interest rates at December 31, 2012, the estimated fair value of the interest rate derivative contracts would be as follows (in thousands):

Scenario	Resulting Classification	Fair Value
Fair value assuming no change in underlying interest rates (as is)	Liability	$ (130,636)
Fair value assuming 10% increase in underlying interest rates	Liability	(116,245)
Fair value assuming 10% decrease in underlying interest rates	Liability	(141,776)

At December 31, 2012, we had total fixed-rate debt obligations at face value of $2,070.2 million. The fair value of these fixed-rate debt obligations at December 31, 2012 was approximately $2,203.7 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, 2012 by approximately $100.7 million or $109.6 million, respectively.

At December 31, 2012, our variable-rate obligations were $871.2 million under the Credit Facility. Based on the balance outstanding at December 31, 2012, we estimate that a 1% increase or decrease in interest rates would increase or decrease annual interest expense by approximately $8.7 million.

See Note 15 in the Notes to Consolidated Financial Statements for additional discussion related to derivative instruments and hedging activities.

Foreign Currency Risk

Puerto Rico is a commonwealth country under the U.S., and thus uses the U.S dollar as its official currency. 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 years ended December 31, 2012 and 2011. There were no effects of foreign currency transactions during the year ended December 31, 2010.

Item 8. *Financial Statements and Supplementary Data*

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Buckeye GP LLC, 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.

Management evaluated the internal control over financial reporting of Buckeye as of December 31, 2012. 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, 2012, 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
Clark C. Smith
Chief Executive Officer, President and Director

/s/ KEITH E. ST.CLAIR
Keith E. St.Clair
Executive Vice President and Chief Financial Officer

February 26, 2013

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, 2012, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Buckeye's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on Buckeye's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Buckeye maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, 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, 2012 of Buckeye and our report dated February 26, 2013 expressed an unqualified opinion on those consolidated financial statements.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2013

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, 2012 and 2011, 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, 2012. 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2013 expressed an unqualified opinion on Buckeye's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 26, 2013

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

	Year Ended December 31,		
	2012	2011	2010
Revenue:			
Product sales	$ 3,332,301	$ 3,844,888	$ 2,469,210
Transportation, storage and other services	1,024,941	914,722	682,058
Total revenue	4,357,242	4,759,610	3,151,268
Costs and expenses:			
Cost of product sales and natural gas storage services	3,344,817	3,851,579	2,462,275
Operating expenses	397,007	366,133	279,164
Depreciation and amortization	146,424	119,534	59,590
General and administrative	69,836	64,122	50,599
Asset impairment expense	59,950	—	—
Goodwill impairment expense	—	169,560	—
Equity plan modification expense	—	—	21,058
Total costs and expenses	4,018,034	4,570,928	2,872,686
Operating income	339,208	188,682	278,582
Other income (expense):			
Earnings from equity investments	6,100	10,434	11,363
Gain on sale of equity investment	—	34,727	—
Interest and debt expense	(114,980)	(119,561)	(89,169)
Other income (expense)	(452)	190	(687)
Total other expense, net	(109,332)	(74,210)	(78,493)
Income before taxes	229,876	114,472	200,089
Income tax benefit	(675)	(192)	(919)
Net income	230,551	114,664	201,008
Less: Net income attributable to noncontrolling interests	(4,134)	(6,163)	(157,928)
Net income attributable to Buckeye Partners, L.P.	$ 226,417	$ 108,501	$ 43,080
Earnings per unit:			
Basic	$ 2.33	$ 1.20	$ 1.66
Diluted	$ 2.32	$ 1.20	$ 1.65
Weighted average units outstanding:			
Basic	97,309	90,423	26,016
Diluted	97,635	90,772	26,086

See Notes to Consolidated Financial Statements

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

	Year Ended December 31,		
	2012	2011	2010
Net income	$ 230,551	$ 114,664	$ 201,008
Other comprehensive income (loss):			
Unrealized losses on derivative instruments	(27,760)	(104,090)	(13,393)
Gain on settlement of treasury lock, net of amortization	(49)	451	—
Adjustments to funded status of benefit plans	(3,229)	(2,843)	(7,019)
Total other comprehensive loss	(31,038)	(106,482)	(20,412)
Comprehensive income	199,513	8,182	180,596
Less: Comprehensive income attributable to noncontrolling interests	(4,134)	(6,163)	(119,647)
Comprehensive income attributable to Buckeye Partners, L.P.	$ 195,379	$ 2,019	$ 60,949

See Notes to Consolidated Financial Statements

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

	December 31, 2012	December 31, 2011
Assets:		
Current assets:		
Cash and cash equivalents	$ 6,776	$ 12,986
Trade receivables, net	262,023	206,601
Construction and pipeline relocation receivables	13,078	8,662
Inventories	259,163	298,304
Derivative assets	1,719	6,756
Prepaid and other current assets	91,563	92,727
Total current assets	634,322	626,036
Property, plant and equipment, net	4,188,648	3,847,573
Equity investments	68,713	65,882
Goodwill	818,121	753,100
Intangible assets, net	219,247	230,568
Other non-current assets	51,958	47,217
Total assets	$ 5,981,009	$ 5,570,376
Liabilities and partners' capital:		
Current liabilities:		
Line of credit	$ 206,200	$ 251,200
Accounts payable	112,792	102,445
Derivative liabilities	82,989	1,859
Accrued and other current liabilities	192,385	199,475
Total current liabilities	594,366	554,979
Long-term debt	2,735,244	2,393,574
Long-term derivative liabilities	57,805	101,911
Other non-current liabilities	204,754	195,955
Total liabilities	3,592,169	3,246,419
Commitments and contingent liabilities (Note 4)	—	—
Partners' capital:		
Buckeye Partners, L.P. capital:		
Limited Partners (90,371,061 and 85,968,423 units outstanding as of December 31, 2012 and 2011, respectively)	2,117,788	2,035,271
Class B Units (7,974,750 and 7,304,880 units outstanding as of December 31, 2012 and 2011, respectively)	413,304	395,639
Accumulated other comprehensive loss	(158,779)	(127,741)
Total Buckeye Partners, L.P. capital	2,372,313	2,303,169
Noncontrolling interests	16,527	20,788
Total partners' capital	2,388,840	2,323,957
Total liabilities and partners' capital	$ 5,981,009	$ 5,570,376

See Notes to Consolidated Financial Statements

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

	Year Ended December 31,		
	2012	2011	2010
Cash flows from operating activities:			
Net income	$ 230,551	$ 114,664	$ 201,008
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
Depreciation and amortization	146,424	119,534	59,590
Asset impairment expense	59,950	—	—
Goodwill impairment expense	—	169,560	—
Net changes in fair value of derivatives	13,336	(66,747)	(45,579)
Non-cash deferred lease expense	3,901	4,122	4,235
Amortization of unfavorable storage contracts	(10,994)	(7,562)	—
Earnings from equity investments	(6,100)	(10,434)	(11,363)
Distributions from equity investments	3,325	6,656	14,679
Equity plan modification expense	—	—	21,058
Other non-cash items	20,914	11,293	5,720
Change in assets and liabilities, net of amounts related to acquisitions:			
Trade receivables	(53,472)	(29,684)	(43,109)
Construction and pipeline relocation receivables	(4,416)	(1,859)	7,292
Inventories	39,141	102,511	9,955
Prepaid and other current assets	(2,326)	(4,220)	16,368
Accounts payable	20,303	29,872	11,808
Accrued and other current liabilities	(20,742)	(16,312)	30,416
Other non-current assets	(1,624)	17,546	9,528
Other non-current liabilities	3,465	(1,504)	(3,872)
Net cash provided by operating activities	441,636	403,892	292,479
Cash flows from investing activities:			
Capital expenditures	(331,338)	(305,324)	(77,699)
Acquisition of interest in equity investment	(350)	(5,723)	(13,512)
Acquisitions, net of cash acquired	(260,312)	(1,084,469)	(46,915)
Proceeds from the sale of equity investment	—	85,000	—
Proceeds from disposal of property, plant and equipment	1,678	237	23,938
Net cash used in investing activities	(590,322)	(1,310,279)	(114,188)
Cash flows from financing activities:			
Net proceeds from issuance of units	246,805	736,871	—
Proceeds from exercise of unit options	1,067	3,567	4,789
Payment of tax withholding on issuance of LTIP awards	(2,604)	—	—
Issuance of long-term debt	—	647,530	—
Repayment of long term-debt	—	(1,525)	(6,178)
Borrowings under BPL Credit Facility	1,040,300	1,221,732	298,400
Repayments under BPL Credit Facility	(699,300)	(995,732)	(278,400)
Net borrowings (repayments) under BES Credit Facility	(45,000)	(33,100)	44,500
Debt issuance costs	—	(9,968)	(3,551)
Acquisition of additional interest in WesPac Memphis	(17,328)	—	—
Repayment of debt assumed in BORCO acquisition	—	(318,167)	—
Credits (costs) associated with agreement and plan of Merger	422	(1,356)	(16,427)
Distributions paid to noncontrolling interests	(10,707)	(8,872)	(195,564)
Proceeds from settlement of treasury lock	—	497	—
Distributions paid to partners of Buckeye GP Holdings L.P.	—	—	(49,808)
Distributions paid to unitholders	(371,179)	(335,730)	—
Net cash provided by (used in) financing activities	142,476	905,747	(202,239)
Net decrease in cash and cash equivalents	(6,210)	(640)	(23,948)
Cash and cash equivalents — Beginning of year	12,986	13,626	37,574
Cash and cash equivalents — End of year	$ 6,776	$ 12,986	$ 13,626

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, 2010	$ 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 (loss)	—	—	—	—	—	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)	—	—	—	—	5,639	(335,730)
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
Net proceeds from issuance of units	—	663,868	73,003	—	—	—	—	736,871
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 loss	—	—	—	—	—	(106,482)	—	(106,482)
Noncash accrual for distribution equivalent rights	—	(1,210)	—	—	—	—	—	(1,210)
Other	—	(492)	—	—	—	—	3,113	2,621
Partners' capital—December 31, 2011	—	2,035,271	395,639	—	—	(127,741)	20,788	2,323,957
Net income	—	208,752	17,665	—	—	—	4,134	230,551
Acquisition of additional interest in WesPac Memphis	—	(14,674)	—	—	—	—	(2,654)	(17,328)
Credits associated with agreement and plan of Merger	—	422	—	—	—	—	—	422
Distributions paid to unitholders	—	(376,177)	—	—	—	—	4,998	(371,179)
Net proceeds from issuance of units	—	246,805	—	—	—	—	—	246,805
Amortization of unit-based compensation awards	—	19,520	—	—	—	—	—	19,520
Proceeds from exercise of unit options	—	1,067	—	—	—	—	—	1,067
Payment of tax withholding on issuance of LTIP awards	—	(2,604)						(2,604)
Distributions paid to noncontrolling interests	—	—	—	—	—	—	(10,707)	(10,707)
Other comprehensive loss	—	—	—	—	—	(31,038)	—	(31,038)
Noncash accrual for distribution equivalent rights	—	(1,328)	—	—	—	—	—	(1,328)
Other	—	734	—	—	—	—	(32)	702
Partners' capital—December 31, 2012	$ —	$2,117,788	$413,304	$ —	$ —	$ (158,779)	$ 16,527	$ 2,388,840

See Notes to Consolidated Financial Statements

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

1. ORGANIZATION

Buckeye Partners, L.P. is a publicly traded Delaware master limited partnership ("MLP"), 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. 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, miles of pipeline, and active product terminals. In addition, we operate and/or maintain 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 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, Buckeye GP Holdings L.P. ("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 regulatory or contractual 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 for costs incurred or settled, accretion expense, and any revisions made to the assumptions related to the retirement costs. Generally, the fair value of the liability is determined based on estimates and assumptions related to (i) future retirement costs, (ii) future inflation rates and, (iii) 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. The significant majority of our rights-of-way agreements 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. In addition, we assume substantially all of our common carrier property operate indefinitely, as these assets generally serve in high-population and high-demand markets. Accordingly, other than with respect to the Natural Gas Storage segment and facilities that are expected to be taken out of service, 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. For the Natural Gas Storage segment, 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 represents our best estimate of the costs to be incurred with information currently available and is based on certain assumptions, including (i) timing of retirement of assets, (ii) methods of abandonment to be employed and (iii) if applicable, our requirements under right-of-way agreements; therefore, it is likely that the ultimate costs to settle this liability will be different and such differences could be material.

The following table presents information regarding our AROs (in thousands):

ARO liability balance, January 1, 2011	$ 1,112
Accretion expense	100
ARO liability balance, December 31, 2011	1,212
Increase in ARO liability (1)	12,100
Accretion expense	112
ARO liability balance, December 31, 2012 (2)	$ 13,424

(1) See Note 7 for a discussion of ARO recorded due to the abandonment of a portion of our NORCO pipeline system.
(2) Amount is included in other non-current liabilities.

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 and operating expenses, (ii) long-term growth rates, and (iii) an appropriate discount rate. 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. See Note 24 for 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, 2012, 2011 and 2010 was $9.2 million, $7.6 million and $2.5 million, respectively. The weighted average rates used to capitalize interest on borrowed funds was 4.5%, 4.2% and 4.8% for the years ended December 31, 2012, 2011 and 2010, 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 fair value of derivatives for our hedging transactions, gain on settlement of treasury lock and adjustment to 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 natural 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,		
	2012	2011	2010
Balance at beginning of period	$ 2,348	$ 2,893	$ 1,544
Charged to expense	1,533	200	4,868
Write-offs, net of recoveries	(456)	(745)	(3,519)
Balance at end of period	$ 3,425	$ 2,348	$ 2,893

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 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, propane, ethanol, biodiesel and middle distillates, such as heating oil, diesel fuel and kerosene, and fuel oil, as well as the effects of hedges of refined petroleum 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 has the obligation 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.

Derivative Instruments

Derivatives are financial and physical instruments whose fair value is determined by changes in a specified benchmark such as interest rates or commodity prices. 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 do not engage in speculative trading activities.

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. Gains and losses related to a derivative instrument designated as a hedge of a 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. In accordance with the hedging requirements, we document all hedging relationships at inception and include 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. We link 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. When an event or transaction occurs, such as hedged fuel inventory is sold or derivative contracts expire, we discontinue hedge accounting. We also formally assess, both at the hedge's inception and on an ongoing basis, 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. We measure ineffectiveness by comparing the change in fair value of the hedge instrument to the change in fair value of the hedged item. The time value component is excluded from our hedge assessment and reported directly in earnings.

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, which 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 indicate remediation efforts are probable, and costs can be reasonably estimated based upon past experience, discussions with operating personnel, advice of outside engineering and consulting firms, discussion with legal counsel or current facts and circumstances. The estimates related to environmental matters are uncertain because (i) estimated future expenditures are subject to cost fluctuations and change in estimated remediation period, (ii) unanticipated liabilities may arise, and (iii) changes in federal, state and local environmental laws and regulations may significantly change the extent of remediation.

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 changes in circumstances indicate that there is an "other than temporary" loss in value of the investment. 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. Estimates of future cash flows include (i) discrete financial forecasts, which rely on management's estimates of revenue and operating expenses, (ii) long-term growth rates and (iii) probabilities assigned to different cash flow scenarios. A significant change in these underlying assumptions could result in recording an impairment charge. There were no impairments of our equity investments during the years ended December 31, 2012, 2011 or 2010.

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. Estimates and assumptions about future events and their effects cannot be made with certainty. Estimates may change as new events occur, when additional information becomes available and if our operating environment changes. 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.

Foreign Currency

Puerto Rico is a commonwealth country under the U.S., and thus uses the U.S. dollar as its official currency. BORCO's functional currency is the U.S. dollar and it is equivalent in value to 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 years ended December 31, 2012 and 2011. There were no effects of foreign currency transactions during the year ended December 31, 2010.

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. 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 indicated. If the carrying amount of a reporting unit exceeds its estimated fair value, an impairment is indicated and the second step of the test is performed to measure the amount of impairment by comparing the implied fair value of the reporting unit goodwill to the carrying amount of that goodwill. The fair value of the reporting unit is allocated 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 the 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 and operating expenses, (ii) long-term growth rates and (iii) an appropriate discount rate. 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 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 income tax returns of our individual partners and may differ significantly from taxable income reportable to our unitholders as a result of differences between the tax basis and financial reporting basis of certain assets and liabilities and other factors. In certain states in which we operate, our operating subsidiaries directly incur income-based state taxes, which are subject to examination by state taxing authorities. In addition, outside the continental U.S., our operations at the BORCO facility are not subject to income taxes by the Bahamian government; however, our operations at the Yabucoa terminal are subject to income taxes within the Commonwealth of Puerto Rico. Buckeye Caribbean Terminals LLC ("Buckeye Caribbean") files annual income tax returns with the Puerto Rico Treasury Department.

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 projected operating income or 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.

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, useful lives of related assets 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, propane, ethanol, biodiesel and middle distillates, such as heating oil, diesel fuel and kerosene. 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 undiscounted future cash flows include (i) discrete financial forecasts, which rely on management's estimates of revenue and operating expenses (ii) long-term growth rates and (iii) estimates of useful lives of the assets. 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 the net income attributable to Buckeye to the LP Unitholders and Class B Unitholders based on the weighted average LP and Class B units outstanding during the period.

Noncontrolling Interests

The consolidated balance sheets and statements of operations include noncontrolling interests that relate primarily to Buckeye Pipe Line Services Company ("Services Company") and portions of Sabina Pipeline and WesPac Pipelines – Memphis LLC ("WesPac Memphis") that are not owned by Buckeye. Additionally, prior to February 16, 2011, a 20% noncontrolling interest of FR Borco Coop Holdings, L.P. ("FRBCH") existed 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. Services Company also sponsors an unfunded post-retirement plan that provides health care and life insurance benefits for certain of its retirees. We develop pension and 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 discount rate, 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, subsea pipelines and docks, 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 land and 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 maintenance and expansion and cost reduction capital expenditures, are recorded at cost. Maintenance capital expenditures maintain and enhance the safety and integrity of our pipelines, terminals, storage facilities and related assets, and expansion and cost reduction capital expenditures expand the reach or capacity of those assets, to improve the efficiency of our operations and to pursue new business opportunities. We charge 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

Reclassification Adjustments Out of Accumulated Other Comprehensive Income ("AOCI"). In February 2013, the Financial Accounting Standards Board ("FASB") issued guidance requiring entities to disclose additional information about reclassification adjustments, including changes in AOCI balances by component and significant items reclassified out of AOCI. Under the new guidance, an entity would (i) disaggregate the total change of each component of OCI and separately present reclassification adjustments and current-period OCI, and (ii) present information about significant items reclassified out of AOCI by component either on the face of the statement where net income is presented or as a separate disclosure in the notes to the financial statements. This guidance is effective for interim and annual periods beginning after December 15, 2012. Since this issuance only impacts the presentation of such financial information, adoption of this guidance is not expected to have an impact on our consolidated financial statements.

Reclassifications

Reclassifications of prior period amounts were made to separately present income tax benefit in our consolidated statement of operations and to components of certain account balances presented in the notes to the consolidated financial statements. Such reclassifications had no impact on net income or partners' capital.

Revenue Recognition

Pipelines & Terminals segment. Revenue from pipeline operations is comprised of tariffs and fees associated with the transportation of refined petroleum products or crude oil at published tariffs as well as revenue associated with line leases for committed capacity on a particular system. Tariff revenue is recognized either at the point of delivery or at the point of receipt, pursuant to specifications outlined in the respective tariffs. Revenue associated with line leases is recognized ratably over the respective lease terms, regardless of whether the capacity is actually utilized, and is subject to take or pay arrangements. All pipeline tariff and fee revenue is based upon 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 revenue. 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 meet the minimum volume commitment has expired.

Revenue from terminalling and storage operations is recognized as services are performed. Storage and terminalling revenue include storage fees that are generated when we provide 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 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 or crude oil 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 meet the minimum volume commitment has expired.

International Operations segment. Revenue from terminalling and storage operations at our Yabucoa and BORCO terminal is recognized as the services are performed. Storage and terminalling revenue includes storage fees that are generated when we provide storage capacity and terminalling fees, or throughput fees, that are generated when we receive refined petroleum products from sea-going vessels or trucks and redeliver such products to customers through marine terminals or truck-loading racks, respectively. Storage fees, which represent fees charged for storage of crude oil and other products, are recognized ratably over the term of the respective contract based on committed gross tank capacity. Revenue from berthing fees and other ancillary services is recognized in the period in which the services are rendered. Berthing fees represent amounts charged to ships that utilize BORCO's jetties. Additionally, revenue from the sale of fuel oil, which is 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.

Natural Gas Storage segment. Revenue from natural gas storage, which consists of demand charges, or lease revenue, 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. Revenue from hub services, which consist of a variety of other natural gas storage services under interruptible storage agreements, is recognized ratably over the term of the agreement. These services principally include parks, loans and injection and withdrawal fees. Parks occur when natural 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. In the event we enter into a park transaction with a customer, the fee to be received or paid is based on the time spread at the time of execution. 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. A loan transaction exposes us to a greater financial risk than a park transaction. We mitigate this exposure by requiring the customer to provide acceptable credit to support the transaction. Injection and withdrawal revenue is a fee charged to inject or withdraw natural gas from the facility on behalf of the customer. The fee is recognized in the period in which the injection or withdrawal occurs.

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. Revenue from contract operation and construction services of facilities and pipelines not directly owned by us is 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

We 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.

BGH GP Holdings LLC ("BGH GP"), who formerly controlled our general partner, established an equity compensation plan ("Equity Compensation Plan") for certain members of BGH GP's senior management, who also serve as our senior management, pursuant to which BGH GP issued both time-based and performance-based awards of the equity of BGH GP (but not our equity), which are called override units. Compensation expense and a corresponding contribution to partners' capital would be recorded based on the fair value of the compensation from distributions paid on vested override units. The vesting of the outstanding override units is contingent on a performance condition and a market condition.

3. ACQUISITIONS AND DISPOSITIONS

Business Combinations

2012 Transaction

In July 2012, we acquired a marine terminal facility for liquid petroleum products in New York Harbor (the "Perth Amboy Facility") from Chevron U.S.A Inc. ("Chevron") for $260.3 million in cash. The facility, which sits on approximately 250 acres on the Arthur Kill tidal strait in Perth Amboy, New Jersey, has over 4.0 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 six miles from our Linden, New Jersey complex. The facility provides a link between our inland pipelines and terminals and our BORCO facility in The Bahamas and opportunities for improved service offerings to our customers. Concurrent with the acquisition, we entered into multi-year storage, blending, and throughput commitments with Chevron. The operations of the Perth Amboy Facility are reported in our Pipelines & Terminals segment. The acquisition cost has been allocated to assets acquired and liabilities assumed based on estimated fair values at the acquisition date, with amounts exceeding the fair value recorded as goodwill, which represents both expected synergies from combining the Perth Amboy Facility with our existing operations and the economic value attributable to future expansion projects resulting from this acquisition. Fair values have been developed using recognized business valuation techniques and are subject to change pending final valuation analysis. The purchase price has been allocated to tangible and intangible assets acquired and liabilities assumed, on a preliminary basis, as follows (in thousands):

Current assets	$ 547
Property, plant and equipment	189,761
Intangible assets	13,350
Goodwill	65,021
Environmental liabilities	(8,367)
Allocated purchase price	$ 260,312

2011 Transactions

In July 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.

In June 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 as follows (in thousands):

Inventory	$ 1,161
Property, plant and equipment	175,577
Intangible assets	8,940
Environmental liabilities	(19,702)
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. At the time of acquisition, BORCO had an aggregate storage capacity of approximately 21.6 million barrels. The acquisition of this terminal facility allowed us to expand and diversify our operations by reaching beyond the continental United States and complemented 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

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

Other Acquisitions

In September 2012, our operating subsidiary, Buckeye Pipe Line Holdings, L.P. ("BPH"), purchased an additional 20% ownership interest in WesPac Pipelines – Memphis LLC ("WesPac Memphis") from Kealine LLC for $17.3 million and, as a result of the acquisition, our ownership interest in WesPac Memphis increased from 50% to 70%. Since BPH retains controlling interest in WesPac Memphis, this acquisition was accounted for as an equity transaction.

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 2,300-miles of 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.

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.

On May 25, 2012, a ship allided with a jetty at our BORCO facility while berthing, causing damage to portions of the jetty. The extent of the damage is being assessed and presently is estimated to range between $20.0 million and $30.0 million. We have insurance to cover this loss, subject to a $5.0 million deductible. On May 26, 2012, we commenced legal proceedings in The Bahamas against the vessel's owner and the vessel to obtain security for the cost of repairs and other losses incurred as a result of the incident. Full security for our claim has been provided by the vessel owner's insurers, reserving all of their defenses, but the vessel owner is claiming it is entitled to limit its liability to approximately $17.0 million. We also have notified the customer on whose behalf the vessel was at the BORCO facility that we intend to hold them responsible for all damages and losses resulting from the incident pursuant to the terms of an agreement between the parties. Any disputes between us and our customer on this matter are subject to arbitration in Houston, Texas. At this time, we have not experienced any material interruption of service at the BORCO facility as a result of the incident and have commenced the process of repairing the jetty. We recorded a $4.2 million loss on disposal due to the assets destroyed in the incident and $3.5 million related to other costs incurred; however, since we believe recovery of our losses is probable, we recorded a corresponding receivable. To the extent the proceeds from the recovery of our losses is in excess of the carrying value of the destroyed assets or other costs incurred, we will recognize a gain when such proceeds are received and are not refundable. As of December 31, 2012, no gain had been recognized.

Federal Energy Regulatory Commission ("FERC") Proceedings

FERC Docket No. IS12-185 – Buckeye Pipe Line Show Cause Proceeding. On March 30, 2012, FERC issued an order (the "Show Cause Order") regarding the market-based methodology used by Buckeye Pipe Line Company, L.P. ("BPLC") to set tariff rates on its pipeline system (the "Buckeye System"). In 1991, BPLC sought and received FERC permission to determine rate changes on the Buckeye System using a unique methodology that constrains rates in markets not found to be competitive based on rate changes in markets that FERC found to be competitive, as well as certain other limits on rate increases. FERC ordered the continuation of this methodology for the Buckeye System in 1994, subject to FERC's authority to cause BPLC to terminate the program in the future. The Show Cause Order, among other things, stated that FERC would review the continued efficacy of BPLC's unique program and directed BPLC to show cause why it should not be required to discontinue the program on the Buckeye System and avail itself of the generic ratemaking methodologies used by other oil pipelines. The Show Cause Order also disallowed proposed rate increases on the Buckeye System that would have become effective April 1, 2012. The Show Cause Order did not impact any of the pipeline systems or terminals owned by Buckeye's other operating subsidiaries. On April 23, 2012, BPLC requested rehearing as to the disallowance of certain rates. On February 22, 2013, FERC issued an order in Dkt. No. IS12-185-000 *et al.* discontinuing the Buckeye Pipe Line Program, and affirming on rehearing its rejection of all rate increases filed in March 2012 ("Ratemaking Methodology Order"). The Ratemaking Methodology Order permitted Buckeye to retain its currently-filed rates in place, to make future rate changes in under market-based ratemaking authority in markets previously found to be competitive by FERC, and to make future changes in rates in other markets pursuant to the generic FERC ratemaking methods, which would include indexing. Pending finality of this order, the timing or outcome of final resolution of this matter cannot reasonably be determined at this time.

FERC Docket No. OR12-28 – Airlines Complaint against BPLC New York City Jet Fuel Rates. On September 20, 2012, a complaint was filed with FERC by Delta Air Lines, JetBlue Airways, United/Continental Air Lines, and US Airways challenging BPLC's rates for transportation of jet fuel from New Jersey to three New York City airports. The complaint was not directed at BPLC's rates for service to other destinations, and does not involve pipeline systems and terminals owned by Buckeye's other operating subsidiaries. The complaint challenges these jet fuel transportation rates as generating revenues in excess of costs and thus being "unjust and unreasonable" under the Interstate Commerce Act. On October 10, 2012, BPLC filed its answer to the complaint, contending that the airlines' allegations are based on inappropriate adjustments to the pipeline's costs and revenues, and that, in any event, any revenue recovery by BPLC in excess of costs would be irrelevant because BPLC's rates are set under a FERC-approved program that ties rates to competitive levels. BPLC also sought dismissal of the complaint to the extent it seeks to challenge the portion of BPLC's rates that were deemed just and reasonable, or "grandfathered," under Section 1803 of the Energy Policy Act of 1992. BPLC further contested the airlines' ability to seek relief as to past charges where the rates are lawful under BPLC's FERC-approved rate program. On October 25, 2012, the complainants filed their answer to BPLC's motion to dismiss and answer. On November 9, 2012, BPLC filed a response addressing newly raised arguments in the complainants' October 25th answer. On February 22, 2013, FERC issued an order setting the airline complaint in Dkt. No. OR12-28-000 for hearing, but holding the hearing in abeyance and setting the dispute for settlement procedures before a settlement judge. If FERC were to find these challenged rates to be in excess of costs and not otherwise protected by law, it could order BPLC to reduce these rates prospectively and could order repayment to the complaining airlines of any past charges found to be in excess of just and reasonable levels for up to two years prior to the filing date of the complaint. BPLC intends to vigorously defend its rates and its existing rate program. The timing or outcome of final resolution of this matter cannot reasonably be determined at this time.

FERC Docket No. OR13-3 – Buckeye Pipe Line's Market-Based Rate Application. On October 15, 2012, BPLC filed an application with FERC seeking authority to charge market-based rates for deliveries of refined petroleum products to the New York City-area market (the "Application"). In the Application, BPLC seeks to charge market-based rates from its three origin points in northeastern New Jersey to its five destinations on its Long Island System, including deliveries of jet fuel to the Newark, LaGuardia, and JFK airports. The jet fuel rates were also the subject of the airlines' OR12-28 complaint discussed above. On December 14, 2012, Delta Air Lines, JetBlue Airways, United/Continental Air Lines, and US Airways filed a joint intervention and protest challenging the Application and requesting its rejection. On January 14, 2013, BPLC filed its answer to the protest and requested summary disposition as to those non-jet-fuel rates that were not challenged in the protest. On January 29, 2013, the protestants responded to BPLC's answer. In addressing the Application, FERC will determine whether to approve the Application, deny it, or set it for further proceedings, including potentially an evidentiary hearing. If FERC were to approve the Application, BPLC would be permitted prospectively to set these rates in response to competitive forces, and the basis for the airlines' claim for relief in their OR12-28 complaint as to BPLC's future rates would be irrelevant prospectively. The timing or outcome of FERC's review of the Application cannot reasonably be determined at this time.

Environmental Contingencies

We recorded operating expenses, net of recoveries, of $6.6 million, $8.4 million, and $3.9 million during the years ended December 31, 2012, 2011, and 2010, respectively, related to environmental remediation expenditures unrelated to claims and legal proceedings. As of December 31, 2012 and 2011, we recorded environmental liabilities of $61.8 million and $58.4 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.

Other Contingencies

The Puerto Rico Treasury Department has notified Buckeye Caribbean of a certain matter 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") in 2002 and 2003, but no preliminary or final notice of debt regarding such matter has been issued. The investment tax credits are not related to income taxes. 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.

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, 2012, 2011, and 2010 was $35.6 million, $30.1 million, and $21.3 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
2013	$ 3,238	$ 3,608	$ 5,763	$ 12,609
2014	3,541	2,093	5,845	11,479
2015	3,620	—	5,968	9,588
2016	3,724	—	6,110	9,834
2017	3,836	—	6,258	10,094
Thereafter	11,786	—	377,273	389,059
Total	$ 29,745	$ 5,701	$ 407,217	$ 442,663

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

(2) Includes leases for properties in connection with both the jetty and inland dock 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 $7.1 million for the years ended December 31, 2012, 2011 and 2010, respectively. At December 31, 2012 and 2011, the balance of our Natural Gas Storage segment deferred lease liability increased by $3.9 million and $4.1 million, respectively, to $21.4 million and $17.5 million, respectively in the years ended December 31, 2012 and 2011. 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 18 years of the lease, since the expected annual lease payments will exceed the amount of lease expense.

Additionally, our rights-of-way payments for the years ended December 31, 2012, 2011, and 2010 were approximately $7.4 million, $6.6 million and $6.0 million, respectively; 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,
2013	$ 20,982
2014	18,290
2015	17,046
2016	16,356
2017	15,928
Thereafter	57,126
Total	$ 145,728

5. INVENTORIES

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

	December 31, 2012	December 31, 2011
Refined petroleum products (1)	$ 246,918	$ 285,509
Materials and supplies	12,245	12,795
Total inventories	$ 259,163	$ 298,304

(1) Ending inventory was 80.9 million and 99.6 million gallons of refined petroleum products at December 31, 2012 and 2011, respectively.

At December 31, 2012 and 2011, approximately 88% and 96% of our refined petroleum products inventory volumes were hedged, respectively. 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, 2012	December 31, 2011
Prepaid insurance	$ 12,585	$ 12,028
Insurance receivables related to environmental remediation reserves	11,081	12,724
Margin deposits	14,038	9,871
Prepaid services	20,031	8,661
Unbilled revenue	2,406	10,090
Prepaid taxes	5,040	1,677
Vendor prepayments	9,480	14,903
Other	16,902	22,773
Total prepaid and other current assets	$ 91,563	$ 92,727

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, 2012	December 31, 2011
Land	N/A	$ 301,604	$ 226,750
Rights-of-way	(1)	107,580	109,325
Pad gas	N/A	29,346	29,346
Buildings and leasehold improvements	13-50	150,720	126,595
Jetties, subsea pipeline and docks	20-50	388,199	357,290
Gas storage facility	25-50	206,467	206,237
Pipelines and terminals	7-50	3,134,340	2,947,643
Vehicles, equipment and office furnishings	3-20	84,549	83,765
Construction in progress	N/A	297,220	178,756
Total property, plant and equipment		4,700,025	4,265,707
Less: Accumulated depreciation		(511,377)	(418,134)
Total property, plant and equipment, net		$ 4,188,648	$ 3,847,573

(1) Rights-of-way assets are depreciated over the useful life of the related pipeline assets.

Depreciation expense was $120.2 million, $105.5 million and $54.7 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Impairment of Long-Lived Assets

During the third and fourth quarters of 2012, management performed extensive integrity tests on a portion of our NORCO pipeline system, consisting of approximately 169 miles of refined petroleum products pipelines and related assets in Indiana and Illinois. Upon completion of the integrity tests in the fourth quarter of 2012, management determined that projected integrity costs, which included work required to maintain the line to our integrity standards, were in excess of the amounts that would be recoverable through operation of the line and proposed the abandonment of this portion of our NORCO pipeline system. On December 13, 2012, the Board of Directors of Buckeye GP (the "Board") approved management's plan. Based on the determination to abandon this pipeline, we were able to estimate the settlement date for the asset retirement obligation and therefore recorded a liability of $12.1 million for our estimated costs of abandonment to be incurred through 2014. The asset retirement obligation represents our best estimate of the costs to be incurred with information currently available and is based on certain assumptions, including assumptions about methods of abandonment to be employed and our requirements in applicable rights-of-way agreements, but because we are still in the early stages of the abandonment process, it is likely that the ultimate costs to abandon this pipeline will differ from our estimate and such differences could be material. We also compared the undiscounted future cash flows to the carrying value of the assets, including the asset retirement cost associated with the removal and decommissioning of the pipeline. Since the carrying value exceeded the undiscounted cash flows, we estimated the fair value of the assets using the expected present value of future cash flows to be minimal and recorded a $60.0 million non-cash asset impairment charge in the Pipelines & Terminals segment. In January 2013, we ceased operations on the affected portion of the system.

8. EQUITY INVESTMENTS

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

		December 31,	
	Ownership	2012	2011
Muskegon Pipeline LLC	40.0%	$ 15,193	$ 14,302
Transport4, LLC	25.0%	417	481
West Shore Pipe Line Company	34.6%	45,953	44,987
South Portland Terminal LLC	50.0%	7,150	6,112
Total equity investments		$ 68,713	$ 65,882

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

	Year Ended December 31,		
	2012	2011	2010
Muskegon Pipeline LLC	$ 891	$ 958	$ 1,482
Transport4, LLC	191	185	162
West Shore Pipe Line Company (1)	4,330	6,605	4,988
West Texas LPG Pipeline Limited Partnership (2)	—	2,297	4,731
South Portland Terminal LLC (3)	688	389	—
Total earnings from equity investments	$ 6,100	$ 10,434	$ 11,363

(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 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, 2012	December 31, 2011 (1)
BALANCE SHEET DATA:		
Current assets	$ 34,861	$ 24,338
Noncurrent assets	75,550	62,305
Total assets	$ 110,411	$ 86,643
Current liabilities	$ 32,887	$ 17,531
Other liabilities	24,561	23,507
Combined equity	52,963	45,605
Total liabilities and combined equity	$ 110,411	$ 86,643

	Year Ended December 31, 2012	2011 (1)	2010
INCOME STATEMENT DATA:			
Revenue	$ 74,691	$ 100,931	$ 139,355
Costs and expenses	(48,708)	(53,596)	(79,584)
Non-operating expense	(8,728)	(13,708)	(12,290)
Net income	$ 17,255	$ 33,627	$ 47,481

(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 date of 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
January 1, 2011	$ 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
Acquisition	65,021	—	—	—	—	65,021
December 31, 2012	$ 313,271	$ 490,536	$ —	$ 1,132	$ 13,182	$ 818,121

For our annual goodwill impairment tests as of January 1, 2013 and 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 value. Based on economic conditions and industry and market considerations, we determined the fair value of the reporting unit exceeded the carrying value; therefore, the two-step impairment test was not required. Additionally, we performed quantitative assessments to determine 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. Therefore, we did not record any goodwill impairment for the year ended December 31, 2012.

During 2011, we concluded that the continued downward performance in operating income and Adjusted EBITDA (as defined in Note 24) in the Natural Gas Storage reporting unit 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 that goodwill in the Natural Gas Storage reporting unit was fully impaired and recorded a non-cash goodwill impairment charge of $169.6 million. 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 assets existed.

We did not record a goodwill impairment charge for the year ended December 31, 2010.

Intangible Assets

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

	December 31, 2012	December 31, 2011
Customer relationships	$ 229,300	$ 229,300
Accumulated amortization	(31,478)	(18,839)
Net carrying amount	197,822	210,461
Customer contracts	42,033	28,683
Accumulated amortization	(20,608)	(8,576)
Net carrying amount	21,425	20,107
Total intangible assets, net	$ 219,247	$ 230,568

For the years ended December 31, 2012, 2011 and 2010, amortization expense related to intangible assets was $24.7 million, $13.4 million and $4.5 million, respectively. Amortization expense related to intangible assets is expected to be approximately $23.3 million for 2013, $17.3 million for 2014, $15.9 million for 2015, $13.5 million for 2016 and $12.8 million for 2017.

10. OTHER NON-CURRENT ASSETS

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

	December 31, 2012	December 31, 2011
Debt issuance costs, net	$ 11,869	$ 14,431
Insurance receivables related to environmental remediation reserves	6,573	4,740
Indemnification asset (see Note 4)	17,720	17,720
Other	15,796	10,326
Total other non-current assets	$ 51,958	$ 47,217

11. ACCRUED AND OTHER CURRENT LIABILITIES

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

	December 31, 2012	December 31, 2011
Taxes—other than income	$ 10,999	$ 26,227
Accrued employee benefit liabilities	3,278	3,071
Accrued environmental liabilities	13,446	12,587
Interest payable	44,137	44,072
Unearned revenue	12,093	9,128
Compensation and vacation	20,870	17,353
Accrued capital expenditures	21,586	16,328
Unfavorable storage contracts (1)	10,994	10,994
Customer deposits	1,237	13,687
Other	53,745	46,028
Total accrued and other current liabilities	$ 192,385	$ 199,475

(1) $11.0 million of revenue was recognized during 2012 and 2011. Revenue to be recognized related to these unfavorable storage contracts is expected to be approximately $11.0 million for 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.

12. LONG-TERM DEBT

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

	December 31, 2012	December 31, 2011
4.625% Notes due July 15, 2013(1) (3)	$ 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	650,000
6.750% Notes due August 15, 2033 (1)	150,000	150,000
BPL Credit Facility due September 26, 2016	871,200	575,200
Unamortized discounts	(4,756)	(5,426)
Total debt	2,941,444	2,644,774
Less: Current portion of line of credit (2)	(206,200)	(251,200)
Total long-term debt	$ 2,735,244	$ 2,393,574

(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) 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.

(3) The $300.0 million of 4.625% Notes maturing on July 15, 2013 has been classified as long-term debt. See below for additional information.

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,
2013	$ 506,200
2014	275,000
2015	—
2016	665,000
2017	125,000
Thereafter	1,375,000
Total	$ 2,946,200

Current Maturities Expected to be Refinanced

It is our intent to refinance the 4.625% Notes in 2013. If necessary, the $300.0 million of 4.625% Notes maturing on July 15, 2013 could be refinanced using our Revolving Credit Facility dated September 26, 2011 (the "Credit Facility") with SunTrust Bank. At December 31, 2012, we had $378.8 million of additional borrowing capacity under our Credit Facility. Therefore, we have classified these notes as long-term debt in the consolidated balance sheet at December 31, 2012. Additionally, we expect to pay approximately $72.8 million to settle interest rate swaps relating to the refinancing of the 4.625% Notes on or before July 15, 2013.

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).

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, 2012 and 2011, Buckeye and BES collectively had $871.2 million and $575.2 million, respectively, outstanding under the Credit Facility, of which BES classified $206.2 million and $251.2 million, respectively, 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 1.5% at December 31, 2012.

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, 2012, our Funded Debt Ratio was approximately 4.74 to 1.00. At December 31, 2012, we were in compliance with the covenants under our Credit Facility.

At December 31, 2012 and 2011, we had committed $11.1 million and $1.5 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.

BES Credit Facility

The BES Credit Facility provided for borrowings of up to $500.0 million with a maturity date of June 25, 2013. 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.

13. OTHER NON-CURRENT LIABILITIES

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

	December 31,	
	2012	2011
Accrued employee benefit liabilities	$ 53,551	$ 51,173
Accrued environmental liabilities	48,348	45,857
Deferred consideration	16,264	17,264
Deferred rent	21,415	17,515
Liability related to investment tax credit (See Note 4)	17,720	17,720
Unfavorable storage contracts (1)	28,151	39,145
ARO (2)	13,424	1,212
Other	5,881	6,069
Total other non-current liabilities	$ 204,754	$ 195,955

(1) See Note 11 for a discussion of the unfavorable storage contracts acquired in connection with the BORCO acquisition.
(2) See Note 7 for a discussion of the ARO recorded in connection with impairment of a portion of our NORCO pipeline system.

14. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	December 31,	
	2012	2011
Adjustments to funded status of benefit plans	$ (23,686)	$ (20,457)
Unrealized losses on derivative instruments	(135,495)	(107,735)
Gain on settlement of treasury lock, net of amortization	402	451
Total accumulated other comprehensive loss	$ (158,779)	$ (127,741)

15. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

We are exposed to financial market risks, including changes in interest rates and commodity prices, in the course of our normal business operations. We use derivative instruments to manage these risks.

Interest Rate Derivatives

We utilize forward-starting interest rate swaps to hedge the variability of the forecasted interest payments on anticipated debt issuances that may result from changes in the benchmark interest rate until the expected debt is issued. 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 instrument 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 impacts the fair value of the swaps. We manage our credit risk by entering into swap transactions only 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.

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. 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. During the years ended December 31, 2012 and 2011, unrealized losses of $28.7 million and $104.8 million, respectively, were recorded in AOCI to reflect the change in the fair values of the forward-starting interest rate swaps.

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 $4.3 million of net losses from accumulated other comprehensive loss to interest and debt expense. The loss consists of the change in fair value on forward-starting interest rate swaps that were settled in 2008 and will settle in 2013, and serve as a designated cash flow hedge of our 6.050% Notes and 4.625% Notes, respectively, partially offset by a gain attributable to the settlement in January 2011 of the treasury lock agreement associated with the 4.875% Notes.

Commodity Derivatives

Our Energy Services segment primarily uses exchange-traded refined petroleum product futures contracts to manage the risk of market price volatility on its refined petroleum product inventories and its physical derivative contracts. The futures contracts used to hedge refined petroleum product inventories are designated as fair value hedges with changes in fair value of both the futures contracts and physical inventory reflected in earnings. Physical contracts and futures contracts that have not been designated in a hedge relationship are marked-to-market.

The following table summarizes our commodity derivative instruments outstanding at December 31, 2012 (amounts in thousands of gallons):

	Volume (1)		
Derivative Purpose	Current	Long-Term (2)	Accounting Treatment
Derivatives NOT designated as hedging instruments:			
Physical fixed price derivative contracts	18,561	—	Mark-to-market
Physical index derivative contracts	127,583	—	Mark-to-market
Future contracts for refined petroleum products	29,064	—	Mark-to-market
Derivatives designated as hedging instruments:			
Future contracts for refined petroleum products	71,568	—	Fair Value Hedge

(1) Volume represents absolute value of net notional volume position.
(2) There were not any derivative contracts that extended beyond December 31, 2013.

The following table sets forth the fair value of each classification of derivative instruments and the locations of the derivative instruments on our consolidated balance sheets at the dates indicated (in thousands):

	December 31, 2012				
	Derivatives NOT Designated as Hedging Instruments	Derivatives Designated as Hedging Instruments	Derivative Carrying Value	Netting Balance Sheet Adjustment	Total
Physical fixed price derivative contracts	$ 1,489	$ —	$ 1,489	$ (335)	$ 1,154
Physical index derivative contracts	724	—	724	(159)	565
Futures contracts for refined products	10,359	435	10,794	(10,794)	—
Total current derivative assets	12,572	435	13,007	(11,288)	1,719
Physical fixed price derivative contracts	(2,377)	—	(2,377)	335	(2,042)
Physical index derivative contracts	(705)	—	(705)	159	(546)
Futures contracts for refined products	(15,268)	(3,096)	(18,364)	10,794	(7,570)
Interest rate derivatives	—	(72,831)	(72,831)	—	(72,831)
Total current derivative liabilities	(18,350)	(75,927)	(94,277)	11,288	(82,989)
Interest rate derivatives	—	(57,805)	(57,805)	—	(57,805)
Total non-current derivative liabilities	—	(57,805)	(57,805)	—	(57,805)
Net derivative assets (liabilities)	$ (5,778)	$ (133,297)	$ (139,075)	$ —	$ (139,075)

	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 fixed price 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)

Our hedged inventory portfolio extends to the third quarter of 2013. The majority of the unrealized loss of $2.7 million at December 31, 2012 for inventory hedges represented by futures contracts will be realized by the first quarter of 2013 as the related inventory is sold. At December 31, 2012, open refined petroleum product derivative contracts (represented by the physical fixed-price contracts, physical index contracts, and futures contracts for fixed-price sales contracts noted above) varied in duration in the overall portfolio, but did not extend beyond December 2013. In addition, at December 31, 2012, we had refined petroleum product inventories that we intend to use to satisfy a portion of the physical derivative contracts.

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

	Location	Year Ended December 31, 2012	Year Ended December 31, 2011
Derivatives NOT designated as hedging instruments:			
Physical fixed price derivative contracts	Product sales	$ (2,795)	$ 5,141
Physical index derivative contracts	Product sales	906	123
Physical fixed price derivative contracts	Cost of product sales and natural gas storage services	1,924	5,968
Physical index derivative contracts	Cost of product sales and natural gas storage services	(922)	98
Futures contracts for refined products	Cost of product sales and natural gas storage services	1,453	7,103
Derivatives designated as fair value hedging instruments:			
Futures contracts for refined products	Cost of product sales and natural gas storage services	$ (29,069)	$ (47,681)
Physical inventory—hedged items	Cost of product sales and natural gas storage services	21,366	37,986
Ineffectiveness and the time value component on fair value hedging instruments:			
Fair value hedge ineffectiveness (excluding time value)	Cost of product sales and natural gas services	$ (4,439)	$ (500)
Time value excluded from hedge assessment	Cost of product sales and natural gas services	(3,264)	(9,195)
Net loss in income		$ (7,703)	$ (9,695)

The 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	Loss Reclassified From AOCI to Income for the Year Ended December 31, 2012	Loss Reclassified From AOCI to Income for the Year Ended December 31, 2011
Derivatives designated as cash flow hedging instruments:			
Futures contracts for natural gas	Cost of product sales and natural gas storage services	$ —	$ (250)
Interest rate contracts	Interest and debt expense	(917)	(920)

	Change in Value Recognized in OCI on Derivatives for the Year Ended December 31, 2012	Change in Value Recognized in OCI on Derivatives for the Year Ended December 31, 2011
Derivatives designated as cash flow hedging instruments:		
Futures contracts for natural gas	$ —	$ (46)
Interest rate contracts	(28,726)	(104,763)

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

	December 31,			
	2012		2011	
	Level 1	Level 2	Level 1	Level 2
Financial assets:				
Physical fixed price derivative contracts	$ —	$ 1,154	$ —	$ 5,292
Physical index derivative contracts	—	565	—	834
Futures contracts for refined products	—	—	630	—
Financial liabilities:				
Physical fixed price derivative contracts	—	(2,042)	—	(1,245)
Physical index derivative contracts	—	(546)	—	(614)
Futures contracts for refined products	(7,570)	—	—	—
Interest rate contracts	—	(130,636)	—	(101,911)
Fair value	$ (7,570)	$ (131,505)	$ 630	$ (97,644)

The values of the Level 1 derivative assets and liabilities were based on quoted market prices obtained from the New York Mercantile Exchange.

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

The values of the Level 2 derivative contracts 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 fixed price derivative assets are net of credit value adjustments ("CVAs") determined using an expected cash flow model, which incorporates assumptions about the credit risk of the 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 CVAs are appropriate because few of the Energy Services segment's customers entering into these derivative contracts are large organizations with nationally-recognized credit ratings. The Level 2 fixed price derivative assets of $1.2 million and $5.3 million as of December 31, 2012 and 2011, respectively, are net of CVA of ($0.1) million for both periods, respectively. As of December 31, 2012, the Energy Services segment did not hold any net liability derivative position containing credit contingent features.

Current assets and 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 carrying value and fair value, using Level 2 input values, of our debt were as follows at the dates indicated (in thousands):

	December 31,			
	2012		2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Fixed-rate debt	$ 2,070,244	$ 2,203,662	$ 2,069,574	$ 2,236,581
Variable-rate debt	871,200	871,200	575,200	575,200
Total debt	$ 2,941,444	$ 3,074,862	$ 2,644,774	$ 2,811,781

In addition, the Partnership's pension plan assets are measured at fair value on a recurring basis, based on Level 1 and Level 3 inputs. See Note 17 for additional information.

Our policy is to recognize transfers between levels within the fair value hierarchy as of the beginning of the reporting period. We did not have any transfers between Level 1 and Level 2 during the years ended December 31, 2012 and 2011, 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, 2012, we recorded a non-cash asset impairment charge of $60.0 million based on Level 3 inputs. See Note 7 for a discussion of our valuation methodology relating to the asset impairment test. 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.

17. PENSIONS AND OTHER POSTRETIREMENT BENEFITS

RIGP and Retiree Medical Plan

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

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

The components of projected benefit obligations and plan assets, and the funded status of the RIGP and the Retiree Medical Plan ("the Plans") were as follows for the periods indicated (in thousands):

	RIGP		Retiree Medical Plan	
	Year Ended December 31,		Year Ended December 31,	
	2012	2011	2012	2011
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 21,291	$ 17,959	$ 38,997	$ 39,835
Service cost	244	284	315	303
Interest cost	827	827	1,794	1,927
Plan participants' contributions	—	—	567	486
Actuarial loss (gain)	2,233	3,689	2,410	(781)
Settlements	(1,853)	(1,375)	—	—
Benefit payments	(85)	(93)	(2,335)	(2,773)
Benefit obligation at end of year	$ 22,657	$ 21,291	$ 41,748	$ 38,997
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 6,618	$ 4,807	$ —	$ —
Actual return on plan assets	488	890	—	—
Plan participants' contributions	—	—	567	486
Employer contributions	2,729	2,389	1,768	2,287
Settlements	(1,853)	(1,375)	—	—
Benefit payments	(85)	(93)	(2,335)	(2,773)
Fair value of plan assets at end of year	$ 7,897	$ 6,618	$ —	$ —
Funded status at end of year	$ (14,760)	$ (14,673)	$ (41,748)	$ (38,997)

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

	RIGP		Retiree Medical Plan	
	December 31,		December 31,	
	2012	2011	2012	2011
Liabilities:				
Accrued employee benefit liabilities—current	$ —	$ —	$ (3,278)	$ (3,071)
Accrued employee benefit liabilities—noncurrent	(14,760)	(14,673)	(38,470)	(35,926)
Total	$ (14,760)	$ (14,673)	$ (41,748)	$ (38,997)
AOCI:				
Net actuarial loss	$ 11,081	$ 11,160	$ 14,229	$ 13,078
Prior service cost (credit)	—	—	(1,624)	(4,353)
Total	$ 11,081	$ 11,160	$ 12,605	$ 8,725

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,	
	2012	2011
Projected benefit obligation	$ 22,657	$ 21,291
Accumulated benefit obligation (1)	17,551	14,687
Fair value of plan assets	7,897	6,618

(1) The accumulated benefit obligation does not include an assumption for future compensation increases.

The weighted average assumptions used in determining net periodic benefit cost for the Plans were as follows for the periods indicated:

	RIGP			Retiree Medical Plan		
	Year Ended December 31,			Year Ended December 31,		
	2012	2011	2010	2012	2011	2010
Discount rate	4.2%	4.7%	5.3%	4.6%	5.1%	5.8%
Expected return on plan assets	5.8%	6.0%	6.0%	N/A	N/A	N/A
Rate of compensation increase	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%

The assumptions used in determining benefit obligations for the Plans were as follows at the dates indicated:

	RIGP		Retiree Medical Plan	
	December 31,		December 31,	
	2012	2011	2012	2011
Discount rate	2.7%	4.2%	3.6%	4.6%
Rate of compensation increase	3.0%	4.0%	3.0%	4.0%

The discount rate reflects the rate at which benefits could be effectively settled on the measurement date. For the years ended December 31, 2012, 2011, and 2010, the discount rate was determined based on a projection of expected cash flows from the Plans using relevant economic benchmarks available as of each year end. The expected return on plan assets was determined based on projected long-term market returns for each asset class in which the Plans are invested, weighted by the target asset class allocations. The rate of compensation increase represents the long-term assumption for future increases to salaries.

The assumed annual rate of increase in the per capita cost of covered health care benefits as of December 31, 2012 in the Retiree Medical Plan was 7.5% for 2013, grading down to 4.5% in 2021, and thereafter. The assumed health care cost trend rates may have a significant effect on the amounts reported for the Retiree Medical Plan. Based on a hypothetical 1% movement in the assumed health care cost trend rates, the change in costs would have had the following effects on the December 31, 2012 results:

	1% Increase	1% (Decrease)
Effect on total service cost and interest cost components	$ 87	$ (78)
Effect on postretirement benefit obligation	1,228	(1,108)

The components of the net periodic benefit cost and other changes recognized in OCI for the Plans were as follows for the periods indicated (in thousands):

	RIGP			Retiree Medical Plan		
	Year Ended December 31,			Year Ended December 31,		
	2012	2011	2010	2012	2011	2010
Components of net periodic benefit cost:						
Service cost	$ 244	$ 284	$ 263	$ 315	$ 303	$ 294
Interest cost	827	827	907	1,794	1,927	1,982
Expected return on plan assets	(453)	(347)	(344)	—	—	—
Amortization of prior service cost	—	—	(46)	(2,730)	(2,964)	(2,964)
Actuarial loss due to settlements	906	694	—	—	—	—
Amortization of unrecognized loss	1,371	1,121	967	1,260	1,244	894
Net periodic benefit cost	$ 2,895	$ 2,579	$ 1,747	$ 639	$ 510	$ 206
Other changes in plan assets and benefit obligations recognized in OCI:						
Net actuarial loss (gain)	$ 2,198	$ 3,287	$ 1,380	$ 2,410	$ (781)	4,490
Amortization of unrecognized loss	(1,371)	(1,121)	(967)	(1,260)	(1,244)	(894)
Actuarial loss due to settlements	(906)	(694)	—	—	—	—
Amortization of prior service cost	—	—	46	2,730	2,964	2,964
Total recognized in OCI	$ (79)	$ 1,472	$ 459	$ 3,880	$ 939	$ 6,560
Total recognized in net period benefit cost and OCI	$ 2,816	$ 4,051	$ 2,206	$ 4,519	$ 1,449	$ 6,766

We expect that the following amounts currently included in OCI for the Plans will be recognized in our consolidated statement of operations during the year ending December 31, 2013 (in thousands):

	RIGP	Retiree Medical Plan
Amortization of unrecognized loss	$ 1,350	$ 1,253
Amortization of prior service cost (credit)	—	(1,624)

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

	RIGP	Retiree Medical Plan
2013	$ 1,475	$ 3,337
2014	1,609	3,367
2015	1,782	3,382
2016	2,210	3,368
2017	2,360	3,284
Thereafter	9,800	14,029

We expect to contribute approximately $4.0 million to our benefit plans in 2013. 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,			
	2012		2011	
	Level 1	Level 3	Level 1	Level 3
Mutual fund—equity securities	$ 1,380	$ —	$ 880	$ —
Mutual fund—money market	2,527	—	1,736	—
Coal lease	—	3,990	—	3,468
Fair value of plan assets	$ 3,907	$ 3,990	$ 2,616	$ 3,468

The values of the Level 1 mutual funds were based on quoted market prices in active markets for identical assets. The mutual fund – equity securities generally seeks long-term growth of capital and income and invests in a portfolio consisting of 100% in equities.

The values of the Level 3 coal lease were determined using an expected present value of future cash flows valuation model. This investment 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,	
	2012	2011
Beginning balance, January 1	$ 3,468	$ 3,438
Lease payments received	407	296
Unrealized gain	522	30
Transfers out of Level 3	(407)	(296)
Ending balance, December 31	$ 3,990	$ 3,468

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 funds with the income derived with proceeds from the coal lease. While no significant changes in the asset class 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 the Retirement and Savings Plan ("RASP") 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 RASP 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 RASP. 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 RASP 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 RASP were approximately $10.0 million, $8.5 million and $6.0 million during the years ended December 31, 2012, 2011 and 2010, respectively.

Services Company also participates in a multi-employer retirement income plan and a multi-employer postretirement benefit plan, both of which provide retirement and 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 costs of providing these benefits, in aggregate, were approximately $0.6 million, $0.5 million and $0.5 million during the years ended December 31, 2012, 2011 and 2010, respectively.

Additionally, certain of our wholly owned subsidiaries, including primarily BORCO, provide a savings and retirement plan to employees. The costs of providing these benefits were approximately $1.4 million, $1.6 million and $0.1 million during the years ended December 31, 2012, 2011 and 2010, respectively.

18. UNIT-BASED COMPENSATION PLANS

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 $19.5 million, $9.2 million and $7.7 million for the years ended December 31, 2012, 2011 and 2010, respectively.

BGH GP established an Equity Compensation Plan for certain members of BGH GP's senior management, who also serve as our senior management. There were no compensation expenses recorded with respect to the override units for the years ended December 31, 2012 and 2011. Compensation expense of $1.2 million was recorded prior to the modification discussed below in 2010. On December 31, 2010, BGH GP modified the Equity Compensation Plan, which resulted in the recognition of $21.1 million of additional compensation expense.

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. 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, 2012, awards representing a total of 552,332 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, 2012, 2011 and 2010, eligible employees were allowed to defer up to 50% of their 2012, 2011, and 2010 compensation award under our Annual Incentive Compensation Plan or other discretionary bonus program in exchange for grants of phantom units equal in value to the amount of their cash award deferral (each such unit, a "Deferral Unit"). Participants also receive one matching phantom unit for each Deferral Unit. Approximately $1.4 million of 2012 compensation awards had been deferred at December 31, 2012 for which phantom units will be granted in 2013. Approximately $0.7 million of 2011 compensation awards had been deferred at December 31, 2011, for which 23,426 phantom units (including matching units) were granted during 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, 2012, the Compensation Committee granted 228,230 phantom units to employees (including the 23,426 phantom units granted pursuant to the Deferral Plan discussed above), 14,000 phantom units to non-employee directors of Buckeye GP, and 133,386 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 $1.4 million and $1.2 million for the years ended December 31, 2012 and 2011, 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 (in thousands, except per unit amounts):

	Number of LP Units		Weighted Average Grant Date Fair Value per LP Unit (1)
Unvested at January 1, 2011	365	$	51.11
Granted	251		64.88
Vested	(18)		55.53
Forfeited	(13)		57.03
Unvested at December 31, 2011	585	$	56.75
Granted	376		63.04
Vested	(166)		50.51
Forfeited	(50)		45.40
Unvested at December 31, 2012	745	$	62.08

(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, 2012, approximately $19.5 million of compensation expense related to the LTIP is expected to be recognized over a weighted average period of approximately 1.8 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 2013, any of our LP Units. Following the adoption of the LTIP plan in 2009, we ceased making additional grants under the Option Plan.

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 (in thousands, except per unit amounts):

	Number of LP Units		Weighted-Average Strike Price ($/LP Unit)	Weighted-Average Remaining Contractual Term (in years)		Aggregate Intrinsic Value (1)
Outstanding at January 1, 2011	242	$	47.04	5.8	$	4,785
Exercised	(145)		47.10			
Outstanding at December 31, 2011	97	$	46.81	4.2	$	1,666
Exercised	(23)		45.62			
Outstanding at December 31, 2012	74	$	47.19	3.3	$	35
Exercisable at December 31, 2012	74	$	47.19	3.3	$	35

(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 2012 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, 2012, 2011 and 2010 was $0.3 million, $2.5 million and $1.7 million, respectively. At December 31, 2012, there was no unrecognized compensation cost related to unvested options as all options were vested as of November 24, 2011. At December 31, 2012, 333,000 LP Units were available for grant in connection with the Option Plan. The fair value of options vested was $0.0 million, $0.2 million and $0.4 million during the years ended December 31, 2012, 2011 and 2010, respectively.

BGH GP's Override Units

Effective on June 25, 2007, BGH GP established an Equity Compensation Plan for certain members of BGH GP's senior management, pursuant to which BGH GP issued both time-based and performance-based awards of the equity of BGH GP (but not our equity), which are called override units. No override units were granted during the year ended December 31, 2012 and 2010. However, on January 27, 2011, BGH GP granted override units in BGH GP to a member of senior management. We are not the sponsor of this plan and have no obligations with respect to it.

On December 31, 2010, pursuant to a modification to the Equity Compensation Plan, certain override units were immediately vested and those vested units were exchanged for LP Units that were owned by BGH GP. As a result of the modification, we recognized additional compensation expense during the year ended December 31, 2010 related to the accelerated vesting and exchange of the override units. For override units with time-based participation, the equity plan modification expense 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 these units immediately prior to the modification. The fair value of these override 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. For override units with performance-based participation, the equity plan modification expense was measured as the fair value of the LP Units received in exchange.

The vesting of the override units that remain unvested is contingent on the satisfaction of a performance condition and a market condition that are dependent on the amounts of distributions that BGH GP makes to its unitholders. Since these conditions were not satisfied during 2012, no compensation expense was recorded for these override units at December 31, 2012.

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. BGH, as primary beneficiary, consolidates Services Company.

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

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 nominal for the year ended December 31, 2012. Total ESOP related costs charged to earnings were $1.2 million and $5.0 million for the years ended December 31, 2011 and 2010, 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. As Services Company is consolidated, these amounts eliminate in consolidation. Services Company, which is beneficially owned by the ESOP, owned 1.1 million of our LP Units (approximately 1.2% of our LP Units outstanding) as of December 31, 2012. 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 $5.0 million, $5.6 million and $5.9 million for the years ended December 31, 2012, 2011 and 2010, 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 years ended December 31, 2012 and 2011. Incentive distribution payments totaled $51.0 million during the year ended December 31, 2010.

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 were 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, which is planned for the second half of 2013, or (b) the third anniversary of the closing of the BORCO acquisition.

Equity Offerings

In 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 at a price of $58.65 per LP Unit, before deducting placement agents' fees and estimated offering expenses. We used the majority of the net proceeds from this offering to reduce the indebtedness outstanding under our Revolving Credit Agreement dated September 26, 2011 (the "Credit Facility") with SunTrust Bank and to indirectly fund a portion of the Perth Amboy Facility acquisition as well as certain other growth capital expenditures.

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

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 Buckeye's and BGH's outstanding units for the periods indicated (in thousands):

	General Partner	Limited Partners	Management Units	Class B Units	Total (1)
Units outstanding at January 1, 2010	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
LP Units issued pursuant to the Option Plan	—	22	—	—	22
LP Units issued pursuant to the LTIP	—	118	—	—	118
Issuance of units to institutional investors	—	4,263	—	—	4,263
Issuance of Class B Units in lieu of quarterly cash distribution	—	—	—	670	670
Units outstanding at December 31, 2012	—	90,371	—	7,975	98,346

(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 unit amounts):

Record Date	Payment Date	Amount Per LP Unit	Limited Partners	General Partner (1)	Total Cash Distributions
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
February 21, 2012	February 29, 2012	$ 1.0375	$ 94,017	$ —	$ 94,017
May 14, 2012	May 31, 2012	1.0375	94,050	—	94,050
August 15, 2012	August 31, 2012	1.0375	94,055	—	94,055
November 12, 2012	November 30, 2012	1.0375	94,055	—	94,055
Total			$ 376,177	$ —	$ 376,177

(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 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 (in thousands):

Record Date	Payment Date	Units
February 21, 2011	February 28, 2011	122
May 16, 2011	May 31, 2011	127
August 15, 2011	August 31, 2011	133
November 14, 2011	November 30, 2011	129
Total		511
February 21, 2012	February 29, 2012	141
May 14, 2012	May 31, 2012	160
August 15, 2012	August 31, 2012	172
November 12, 2012	November 30, 2012	197
Total		670

On February 8, 2013, we announced a quarterly distribution of $1.0375 per LP Unit that will be paid on February 28, 2013, to unitholders of record on February 19, 2013. Based on the LP Units outstanding as of December 31, 2012 and the 6.9 million LP units issued in connection with our January 2013 equity offering, cash distributed to LP unitholders on February 28, 2013 will total approximately $101.2 million. Based on Class B Units outstanding as of December 31, 2012, we also expect to issue approximately 186,000 Class B Units in lieu of cash distributions on February 28, 2013 to Class B unitholders of record on February 19, 2013.

22. INCOME TAXES

As of December 31, 2012 and 2011, we had net deferred tax assets of approximately $1.7 million and $0.3 million, respectively, for BDL, which are not expected to be realized based on the available evidence of projected operating losses for the foreseeable future, and have provided a full valuation allowance against the deferred tax assets as of the end of each year. As of December 31, 2012, approximately $3.5 million of BDL's deferred tax assets related to net operating loss carryforwards, which will expire between 2028 and 2032.

As of December 31, 2012 and 2011, we had net deferred tax assets of $34.3 million and $34.5 million related to Buckeye Caribbean. As of December 31, 2012, approximately $14.7 million of the deferred tax assets related to net operating loss carryforwards, and unless utilized, the tax benefits of the net operating loss carryforwards will expire between 2018 and 2020. Based on available evidence, we had recorded a full valuation allowance against the 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 continued to carry a full valuation allowance against the deferred tax assets. However, based on our assessment at December 31, 2012, we concluded that sufficient positive evidence exists, including the realization of taxable income in the current year primarily related to Buckeye Caribbean's entry into the fuel oil business, and a forecast of future taxable income, to release $1.8 million of the valuation allowance for the year ended December 31, 2012.

The tax effects of significant items comprising our net deferred tax assets and liabilities at December 31, 2012 and 2011 are as follows (in thousands):

	December 31,	
	2012	2011
Deferred tax asset:		
Net operating loss carryforward	$ 18,163	$ 17,227
Property, plant and equipment—refinery	17,179	17,179
Other	2,982	2,821
Total deferred tax asset	$ 38,324	$ 37,227
Deferred tax liability:		
Property, plant and equipment—terminals	$ 2,142	$ 2,161
Other	141	190
Total deferred tax liability	2,283	2,351
Net deferred tax asset	36,041	34,876
Less: Valuation allowance	(34,271)	(34,876)
Deferred taxes, net	$ 1,770	$ —

We have no unrecognized tax benefits related to uncertain tax positions. As of December 31, 2012, BDL's tax years from 2009 to 2012 and Buckeye Caribbean's tax years from 2006 through 2012 were subject to examination by the Internal Revenue Service and Puerto Rico Treasury Department, respectively. We are currently not under any income tax audits or examinations.

23. EARNINGS PER UNIT

Basic and diluted earnings per unit (includes LP Units and Class B Units in 2012 and 2011) is calculated by dividing net income, after deducting the amount allocated to noncontrolling interests, by the weighted-average number of LP Units and Class B Units outstanding during the period.

Pursuant to the Merger Agreement, BGH's unitholders received a total of approximately 20.0 million of Buckeye's LP Units in 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.

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,		
	2012	2011	2010
Net income attributable to Buckeye Partners, L.P.	$ 226,417	$ 108,501	$ 43,080
Basic:			
Weighted average units outstanding	97,309	90,423	25,627
Weighted average management units outstanding	—	—	389
Weighted average units outstanding—basic	97,309	90,423	26,016
Earnings per unit—basic	$ 2.33	$ 1.20	$ 1.66
Diluted:			
Weighted average units outstanding—basic	97,309	90,423	26,016
Dilutive effect of LP Unit options and LTIP awards granted	326	349	70
Weighted average units outstanding—diluted	97,635	90,772	26,086
Earnings per unit—diluted	$ 2.32	$ 1.20	$ 1.65

24. 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.

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 pipeline systems and refined petroleum products terminals in the continental United States, including five terminals owned by the Energy Services segment but operated by the Pipelines & Terminals segment. In addition, we provide crude oil services, including train off-loading, storage and throughput. The segment includes our recent acquisition of the Perth Amboy Facility. See Note 3 for information regarding the Perth Amboy Facility acquisition.

International Operations

The International Operations segment provides marine bulk storage and marine terminal throughput services. The segment has two liquid petroleum product terminals, one in Puerto Rico and one on Grand Bahama Island in The Bahamas. In connection with BORCO's publicly announced expansion plans, BORCO completed construction of and brought online incremental storage capacity in the second half of 2012. Additionally, the segment provides fuel oil supply and distribution services to third parties in the Caribbean.

Natural Gas Storage

The Natural Gas Storage segment provides natural gas storage services at a natural gas storage facility in Northern California. The facility 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, ethanol, biodiesel and petroleum distillates such as heating oil, diesel fuel and kerosene. The segment owns five terminals which are operated by the Pipelines & Terminals segment. 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 operations of third-party pipelines, 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. Additionally, the Development & Logistics segment includes our ownership and operation of two underground propane storage caverns in Indiana and Illinois and an ammonia pipeline, as well as our majority ownership of the Sabina Pipeline, located in Texas.

Adjusted EBITDA

Adjusted EBITDA is the primary measure used by our senior management, including our Chief Executive Officer, to: (i) evaluate our consolidated operating performance and the operating performance of our business segments; (ii) allocate resources and capital to business segments; (iii) evaluate the viability of proposed projects; and (iv) determine overall rates of return on alternative investment opportunities. Adjusted EBITDA eliminates (i) non-cash expenses, including but not limited to depreciation and amortization expense resulting from the significant capital investments we make in our businesses and from intangible assets recognized in business combinations; (ii) charges for obligations expected to be settled with the issuance of equity instruments; and (iii) items that are not indicative of our core operating performance results and business outlook.

We believe that investors benefit from having access to the same financial measures that we use and that these measures are useful to investors because they aid in comparing our operating performance with that of other companies with similar operations. The Adjusted EBITDA data presented by us may not be comparable to similarly titled measures at other companies because these items may be defined differently 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.

The following tables summarize our financial information by each segment for the periods indicated (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Revenue:			
Pipelines & Terminals	$ 719,126	$ 631,289	$ 574,990
International Operations (1)	254,362	193,960	936
Natural Gas Storage	71,339	65,990	95,337
Energy Services	3,293,274	3,888,961	2,481,566
Development & Logistics	50,211	43,068	37,696
Intersegment	(31,070)	(63,658)	(39,257)
Total revenue	$ 4,357,242	$ 4,759,610	$ 3,151,268

(1) The International Operations segment's revenue generated in The Bahamas was $193.4 million and $177.6 million for the years ended December 31, 2012 and 2011, respectively, which represents 76.0% and 91.6%, respectively, of the International Operations segment's total revenue for the periods. The remainder relates primarily to the fuel oil supply and distribution services in the Caribbean.

For the years ended December 31, 2012, 2011 and 2010, no customer contributed 10% or more of consolidated revenue.

	Year Ended December 31,		
	2012	2011	2010
Capital additions, net: (1)			
Pipelines & Terminals	$ 156,056	$ 103,678	$ 65,527
International Operations	169,699	184,438	—
Natural Gas Storage	2,369	10,097	8,328
Energy Services	2,490	1,824	2,961
Development & Logistics	724	5,287	883
Total capital additions, net	$ 331,338	$ 305,324	$ 77,699
Total Assets:			
Pipelines & Terminals (2)	$ 2,934,365	$ 2,566,471	
International Operations (3)	2,146,085	2,041,209	
Natural Gas Storage	372,369	365,514	
Energy Services	450,511	518,438	
Development & Logistics	77,679	78,744	
Total assets	$ 5,981,009	$ 5,570,376	

(1) Amounts represent cash paid for capital expenditures and exclude ($2.4) million, $14.3 million and $0.4 million of non-cash changes in accounts payable and accruals for capital expenditures for the years ended December 31, 2012, 2011 and 2010, respectively (see Note 25).

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

(3) The International Operations segment's long-lived assets consist of property, plant and equipment, goodwill, intangible assets and other non-current assets. Total tangible long-lived assets located in or attributable to The Bahamas was $1,381.6 million and $1,279.6 million for the years ended December 31, 2012 and 2011, respectively, which represents 97.7% and 97.6%, respectively, of the International Operations segment's total tangible long-lived assets.

The following tables present Adjusted EBITDA by segment and on a consolidated basis and a reconciliation of net income (loss) to Adjusted EBITDA for the periods indicated (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Adjusted EBITDA:			
Pipeline & Terminals	$ 409,055	$ 361,018	$ 346,447
International Operations	132,104	112,996	(4,655)
Natural Gas Storage	6,118	4,204	29,794
Energy Services	524	1,797	5,861
Development & Logistics	11,722	7,932	5,193
Total Adjusted EBITDA	$ 559,523	$ 487,947	$ 382,640
Reconciliation of Net Income to Adjusted EBITDA:			
Net income	$ 230,551	$ 114,664	$ 201,008
Less: Net income attributable to noncontrolling interests	(4,134)	(6,163)	(157,928)
Net income attributable to Buckeye Partners, L.P.	226,417	108,501	43,080
Add: Interest and debt expense	114,980	119,561	89,169
Income tax benefit	(675)	(192)	(919)
Depreciation and amortization	146,424	119,534	59,590
Non-cash deferred lease expense	3,901	4,122	4,235
Non-cash unit-based compensation expense	19,520	9,150	8,960
Asset impairment expense	59,950	—	—
Goodwill impairment expense	—	169,560	—
Equity plan modification expense	—	—	21,058
Net income attributable to noncontrolling interests affected by Merger (1)	—	—	157,467
Less: Amortization of unfavorable storage contracts (2)	(10,994)	(7,562)	—
Gain on sale of equity investment	—	(34,727)	—
Adjusted EBITDA	$ 559,523	$ 487,947	$ 382,640

(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 for comparability purposes.

(2) Represents amortization of negative fair values allocated to certain unfavorable storage contracts acquired in connection with the BORCO acquisition.

25. SUPPLEMENTAL CASH FLOW INFORMATION

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

	Year Ended December 31,		
	2012	2011	2010
Cash paid for interest (net of capitalized interest)	$ 110,769	$ 98,044	$ 83,852
Cash paid for income taxes	1,406	1,147	941
Capitalized interest	9,238	7,583	2,499
Non-cash investing activities:			
Increase (decrease) in accounts payable and accrued and other current liabilities related to capital expenditures	$ (2,401)	$ 14,296	$ 421
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	31,264	28,111	—

26. 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
2012					
Revenue	$1,259,439	$ 982,640	$ 965,970	$1,149,193	$4,357,242
Operating income (1)	80,734	82,146	113,864	62,464	339,208
Net income (1)	53,467	56,026	85,259	35,799	230,551
Net income attributable to Buckeye Partners, L.P. (1)	51,959	54,379	85,116	34,963	226,417
Earnings per unit—basic	$ 0.55	$ 0.56	$ 0.87	$ 0.36	$ 2.33
Earnings per unit—diluted	$ 0.54	$ 0.55	$ 0.87	$ 0.35	$ 2.32
2011					
Revenue	$1,252,536	$1,077,092	$1,116,911	$1,313,071	$4,759,610
Operating income (loss) (2)	92,387	85,918	(77,305)	87,681	188,682
Net income (loss) (2)	67,813	93,592	(108,200)	61,459	114,664
Net income (loss) attributable to Buckeye Partners, L.P. (2)	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

(1) During the fourth quarter of 2012, we recorded a $60.0 million asset impairment expense (see Note 7).

(2) We recognized a $34.1 million gain and $0.6 million of subsequent dividend income related to the sale of our equity interest in WT LPG during the second quarter and fourth quarter of 2011, respectively (see Note 3). During the third quarter of 2011, we recorded a $169.6 million goodwill impairment (see Note 9).

27. SUBSEQUENT EVENTS

FERC Proceedings Update

On February 22, 2013, the FERC issued two orders related to proceedings pending before FERC. The first order permits BPLC to continue charging its current tariff rates and gives BPLC full market-based-rate authority in markets FERC previously found to be competitive. The second order relates to the complaint filed by several airlines challenging BPLC's rates for transportation of jet fuel to three New York City area airports. This order sets the matter for hearing, but orders that such hearing be held in abeyance pending the outcome of FERC-ordered settlement discussions between the parties, which are to be facilitated by a FERC-appointed settlement judge. See Note 4 for additional information.

Equity Offering

In January 2013, we completed a public offering of 6,000,000 LP Units pursuant to an effective shelf registration statement, which priced at $52.54 per unit. The underwriters also exercised an option to purchase 900,000 additional LP Units, resulting in total gross proceeds of approximately $362.5 million before deducting underwriting fees and estimated offering expenses. We used the net proceeds from this offering to reduce the indebtedness outstanding under our revolving 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 2012, 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 2013 Annual Meeting of unitholders (the "2013 Proxy Statement"), which will be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2012, 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 2013 Proxy Statement, which will be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2012, 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 2013 Proxy Statement, which will be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2012, 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 2013 Proxy Statement, which will be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2012, 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 2013 Proxy Statement, which will be filed with the SEC within 120 days after the end of the fiscal year ended December 31, 2012, 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	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). †
2.2	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). †
2.3	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).
2.4	Purchase and Sale Agreement by and between Buckeye Tank Terminals LLC and Chevron U.S.A., Inc., dated as of February 8, 2012 (Incorporated by reference to Exhibit 2.1 of Buckeye Partners, L.P.'s Current Report on Form 8-K filed on February 10, 2012).
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., 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).

4.10 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 February 21, 2013, among Buckeye Partners, L.P., certain operating subsidiaries of Buckeye Partners, L.P. and Services Company.

10.3 Form of Severance Agreement for each Named Executive Officer (except Mr. Wylie) (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P.'s Current Report on Form 8-K filed on January 20, 2012).

10.4 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).

10.5 Buckeye Partners, L.P. 2009 Long-Term Incentive Plan, as amended and restated effective August 3, 2011 (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P.'s Current Report on Form 8-K filed on August 9, 2011).

10.6 Buckeye Partners, L.P. Annual Incentive Compensation Plan (as amended and restated, effective January 1, 2012) (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P.'s Current Report on Form 8-K filed on April 23, 2012).

10.7 Buckeye Partners, L.P. Unit Deferral and Incentive Plan, as amended and restated effective January 1, 2013.

**10.8*	Buckeye Partners, L.P. Non-Employee Director Deferred Compensation Plan, effective as of January 1, 2013.
**10.9*	Buckeye Pipe Line Company Benefit Equalization Plan, effective as of January 1, 2012.
10.10	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).
10.11	Transition Support Agreement by and among Buckeye Atlantic Holdings LLC, Vopak Bahamas B.V., FR Borco Topco L.P., FR Borco Coop Holdings, L.P., FR Borco Coop Holdings GP Limited, Bahamas Oil Refining Company International Limited and Vopak Koninklijke N.V. dated as of February 15, 2011 (Incorporated by reference to Exhibit 10.1 of Buckeye Partners, L.P.'s Current Report of Form 8-K filed on February 22, 2011).
**12.1	Computation of Ratio of Earnings to Fixed Charges.
**21.1	List of Subsidiaries of Buckeye Partners, L.P.
**23.1	Consent of Deloitte & Touche LLP.
**31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14 (a) under the Securities Exchange Act of 1934.
**31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
**32.1	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
**32.2	Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
**101.INS	XBRL Instance Document.
**101.SCH	XBRL Taxonomy Extension Schema Document.
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

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* Represents management contract or compensatory plan or arrangement.

** Filed herewith.

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

(a) Exhibits – See Item 15(a)(3) above.

SIGNATURES

Pursuant to the requirements of Section 13 of 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BUCKEYE PARTNERS, L.P.
(Registrant)
By: Buckeye GP LLC,
as General Partner

Dated: February 26, 2013

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 26, 2013	By: /s/ PIETER BAKKER Pieter Bakker *Director*
Dated: February 26, 2013	By: /s/ C. SCOTT HOBBS C. Scott Hobbs *Director*
Dated: February 26, 2013	By: /s/ JOSEPH A. LASALA, JR. Joseph A. LaSala, Jr. *Director*
Dated: February 26, 2013	By: /s/ MARK C. MCKINLEY Mark C. McKinley *Director*
Dated: February 26, 2013	By: /s/ OLIVER G. "RICK" RICHARD, III Oliver "Rick" G. Richard, III *Director*
Dated: February 26, 2013	By: /s/ CLARK SMITH Clark Smith *Chief Executive Officer, President and Director* *(Principal Executive Officer)*
Dated: February 26, 2013	By: /s/ FRANK S. SOWINSKI Frank S. Sowinski *Director*
Dated: February 26, 2013	By: /s/ KEITH E. ST.CLAIR Keith E. St.Clair *Executive Vice President and Chief Financial Officer* *(Principal Financial Officer)*
Dated: February 26, 2013	By: /s/ MARTIN A. WHITE Martin A. White *Director*
Dated: February 26, 2013	By: /s/ FORREST E. WYLIE Forrest E. Wylie *Non-Executive Chairman of the Board*
Dated: February 26, 2013	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.

Adjusted EBITDA and distributable cash flow are measures not defined by GAAP. Adjusted EBITDA is the primary measure used by our senior management, including our Chief Executive Officer, to (i) evaluate our consolidated operating performance and the operating performance of our business segments, (ii) allocate resources and capital to business segments, (iii) evaluate the viability of proposed projects, and (iv) determine overall rates of return on alternative investment opportunities. Distributable cash flow is another measure used by our senior management to provide a clearer picture of Buckeye's cash available for distribution to its unitholders. Adjusted EBITDA and distributable cash flow eliminate (i) non-cash expenses, including, but not limited to, depreciation and amortization expense resulting from the significant capital investments we make in our businesses and from intangible assets recognized in business combinations, (ii) charges for obligations expected to be settled with the issuance of equity instruments, and (iii) items that are not indicative of our core operating performance results and business outlook.

Buckeye believes that investors benefit from having access to the same financial measures used by senior management and that these measures are useful to investors because they aid in comparing Buckeye's operating performance with that of other companies with similar operations. The Adjusted EBITDA and distributable cash flow data presented by Buckeye may not be comparable to similarly titled measures at other companies because these items may be defined differently by other companies. Please see the attached reconciliations of each of Adjusted EBITDA and distributable cash flow to net income.

(in millions except for ratio)	2012	2011	2010	2009	2008
Net Income	$230.5	$114.7	$201.0	$141.6	$180.6
Less: Noncontrolling interests	(4.1)	(6.2)	(157.9)	(92.0)	(154.1)
Net income attributable to Buckeye Partners, L.P.	226.4	108.5	43.1	49.6	26.5
Interest and debt expense	115.0	119.6	89.2	75.1	75.4
Income tax expense (benefit)	(0.7)	(0.2)	(1.0)	(0.3)	0.8
Depreciation and amortization	146.4	119.5	59.6	54.7	50.8
EBITDA	$487.1	$347.4	$190.9	$179.1	$153.5
Net income attributable to noncontrolling interests affected by merger	---	---	157.5	90.4	153.5
Non-cash deferred lease expense	3.9	4.1	4.2	4.5	4.6
Non-cash unit-based compensation expense	19.5	9.1	8.9	4.4	2.0
Asset impairment expense	60.0	---	---	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	(11.0)	(7.6)	---	---	---
Adjusted EBITDA	**$559.5**	**$487.9**	**$382.6**	**$370.2**	**$313.6**
Less: Interest and debt expense[(1)]	(111.5)	(111.9)	(84.8)	(71.9)	(73.6)
Less: Maintenance capital expenditures	(54.4)	(57.5)	(31.2)	(23.5)	(28.9)
Less: Income taxes, excluding non-cash taxes	(1.1)	---	---	0.3	1.2
Distributable cash flow	**$392.5**	**$318.5**	**$266.6**	**$275.1**	**$212.3**
Distributions used for coverage ratio	376.2	351.2	259.3	237.7	209.4
Coverage Ratio	**1.04x**	**0.91x**	**1.03x**	**1.16x**	**1.01x**

(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 2008-2010 has been restated to exclude those amounts for comparison purposes.

	2012	2011	2010	2009	2008
Operating income before special charges:					
Operating income	$339.2	$188.7	$278.6	$203.5	$247.3
Asset impairment expense	60.0	---	---	59.7	---
Reorganization expense	---	---	---	32.1	---
Equity plan modification expense	---	---	21.1	---	---
Goodwill impairment expense	---	169.6	---	---	---
Operating income before special charges	$399.2	$358.3	$299.7	$295.3	$247.3

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Information

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.

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or visit the Investor Center pages
at our website: www.buckeye.com

Board of Directors & Senior Management

Board of 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

Front row:
Mark C. McKinley, Frank S. Sowinski, Forrest E. Wylie, C. Scott Hobbs

Second row:
Martin A. White, Oliver G. "Rick" Richard, III, Clark C. Smith, Joseph A. LaSala, Jr., Pieter Bakker

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

Todd J. Russo
Vice President and General Counsel

Front row:
Mary F. Morgan, Clark C. Smith, Jeremiah J. Ashcroft, III

Second row:
Mark S. Esselman, Khalid A. Muslih, Robert A. Malecky, Todd J. Russo, Keith E. St.Clair

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