

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

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2011

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to _____

Commission file number: 01-32665

BOARDWALK PIPELINE PARTNERS, LP
(Exact name of registrant as specified in its charter)

DELAWARE
(State or other jurisdiction of incorporation or organization)

20-3265614
(I.R.S. Employer Identification No.)

9 Greenway Plaza, Suite 2800
Houston, Texas 77046
(866) 913-2122

(Address and Telephone Number of Registrant's Principal Executive Office)

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

<i>Title of each class</i>	<i>Name of each exchange on which registered</i>
Common Units	
Representing Limited	New York Stock Exchange
Partner Interests	

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 Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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 ☐ 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 ☒

The aggregate market value of the common units of the registrant held by non-affiliates as of June 30, 2011, was approximately \$2.1 billion. As of February 21, 2012, the registrant had 184,921,916 common units outstanding and 22,866,667 Class B units outstanding.

Documents incorporated by reference. None.

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PART I

Item 1. Business

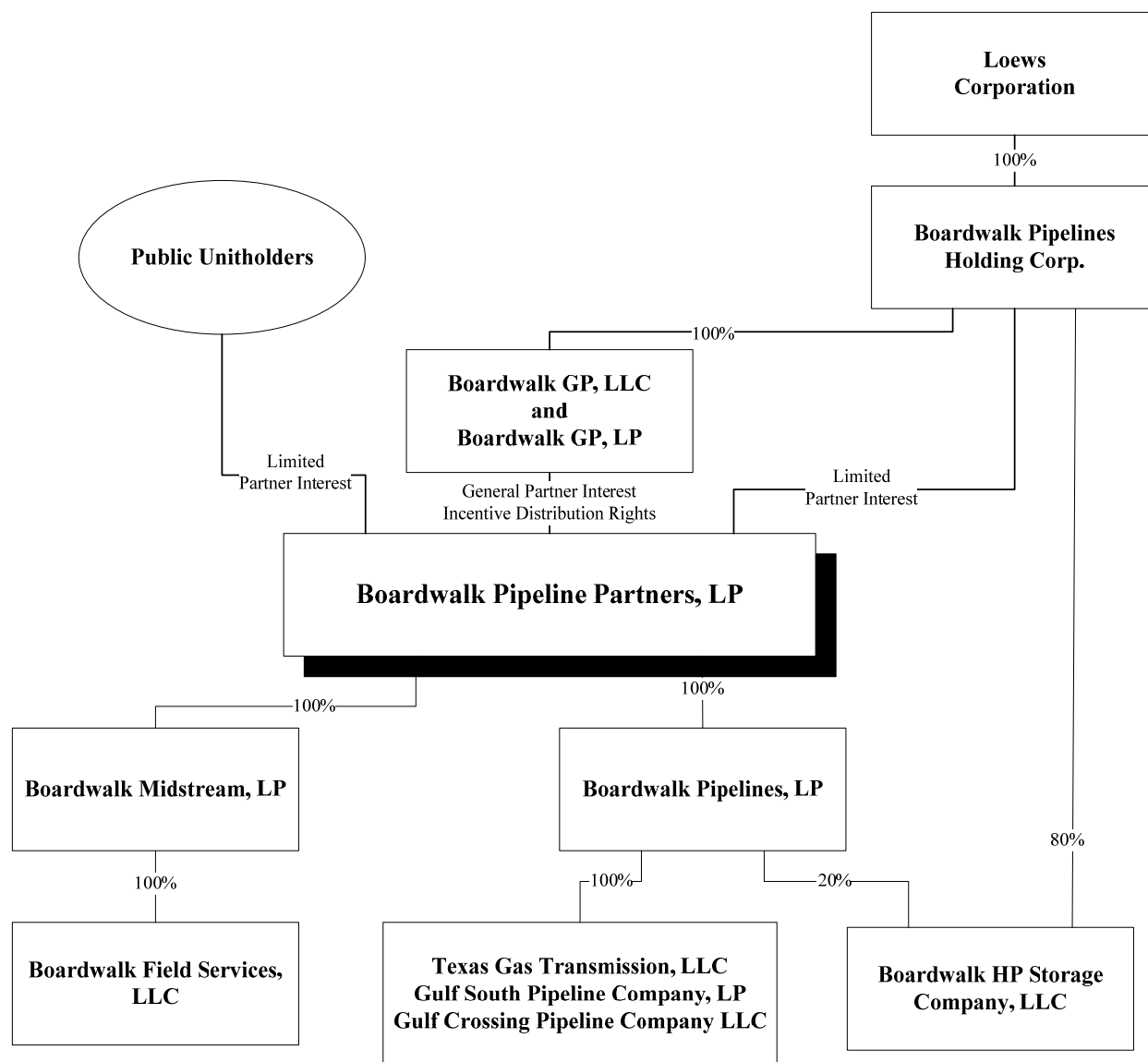
Unless the context otherwise requires, references in this Report to “we,” “our,” “us” or like terms refer to the business of Boardwalk Pipeline Partners, LP and its consolidated subsidiaries.

Introduction

We are a Delaware limited partnership formed in 2005. Our business is conducted by our primary subsidiary, Boardwalk Pipelines, LP (Boardwalk Pipelines) and its subsidiaries, Gulf Crossing Pipeline Company LLC (Gulf Crossing), Gulf South Pipeline Company, LP (Gulf South) and Texas Gas Transmission, LLC (Texas Gas) (together, the operating subsidiaries), which consist of integrated natural gas pipeline and storage systems. In 2011, we formed Boardwalk Midstream, LP (Midstream), and its operating subsidiary, Boardwalk Field Services, LLC (Field Services), which is engaged in the natural gas gathering and processing business. Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews), owns 102.7 million of our common units, all 22.9 million of our class B units and, through Boardwalk GP, LP (Boardwalk GP), an indirect wholly-owned subsidiary of BPHC, holds the 2% general partner interest and all of our incentive distribution rights (IDRs). As of February 21, 2012, the common units, class B units and general partner interest owned by BPHC represent approximately 61% of our equity interests, excluding the IDRs. *Our Partnership Interests*, in Item 5 contains more information on how we calculate BPHC’s equity ownership. Our common units are traded under the symbol “BWP” on the New York Stock Exchange (NYSE).

In December 2011, Boardwalk HP Storage Company, LLC (HP Storage), a joint venture between Boardwalk Pipelines and BPHC, acquired Petal Gas Storage, L.L.C. (Petal), Hattiesburg Gas Storage Company (Hattiesburg) and related entities for approximately \$550.0 million in cash. HP Storage funded the acquisition with borrowings under a new \$200.0 million five-year bank loan and equity contributions from Boardwalk Pipelines and BPHC. BPHC contributed \$280.0 million towards the purchase price for an 80% equity ownership interest in HP Storage and Boardwalk Pipelines contributed \$70.0 million for a 20% equity ownership interest. Petal and Hattiesburg own high deliverability salt dome natural gas storage caverns and a natural gas transmission pipeline in Forrest County, Mississippi.

The following diagram reflects a simplified version of our organizational structure as of December 31, 2011:



Our Business

We own and operate three interstate natural gas pipeline systems including integrated storage facilities. Our pipeline systems originate in the Gulf Coast region, Oklahoma and Arkansas and extend north and east to the midwestern states of Tennessee, Kentucky, Illinois, Indiana and Ohio.

We serve a broad mix of customers, including producers, local distribution companies (LDCs), marketers, electric power generators, direct industrial users and interstate and intrastate pipelines. We provide a significant portion of our pipeline transportation and storage services through firm contracts under which our customers pay monthly capacity reservation charges (which are charges owed regardless of actual pipeline or storage capacity utilization). Other charges are based on actual utilization of the capacity under firm contracts and contracts for interruptible services. For the twelve months ended December 31, 2011, approximately 82% of our revenues were derived from capacity reservation charges under firm contracts, approximately 14% of our revenues were derived from charges based on actual utilization under firm contracts and approximately 4% of our revenues were derived from interruptible transportation, interruptible storage, parking and lending (PAL) and other services. Item 6 of this Report contains a summary of our revenues from external customers, net income and total assets, all of which were earned by our pipeline and storage systems.

Our transportation and storage rates and general terms and conditions of service are established by, and subject to review and revision by, the Federal Energy Regulatory Commission (FERC). These rates are based upon certain assumptions to allow us the opportunity to recover the cost of providing our transportation and storage services and earn a reasonable return on equity. However, it is possible that we may not recover those costs or earn a reasonable return. Our firm and interruptible storage rates for Gulf South and the storage services associated with a portion of the working gas capacity on Texas Gas are market-based pursuant to authority granted by FERC.

Our Pipeline and Storage Systems

Our operating subsidiaries own and operate approximately 14,200 miles of pipelines, directly serving customers in twelve states and indirectly serving customers throughout the northeastern and southeastern United States (U.S.) through numerous interconnections with unaffiliated pipelines. In 2011, our pipeline systems transported approximately 2.7 trillion cubic feet (Tcf) of gas. Average daily throughput on our pipeline systems during 2011 was approximately 7.3 billion cubic feet (Bcf). Our natural gas storage facilities are comprised of eleven underground storage fields located in four states with aggregate working gas capacity of approximately 167.0 Bcf. In December 2011, we acquired a 20% equity interest in HP Storage which owns seven high deliverability salt dome natural gas storage caverns and related assets in Forrest County, Mississippi, having approximately 29.0 Bcf of total storage capacity, of which approximately 18.6 Bcf is working gas capacity. We operate the assets of HP Storage on behalf of the joint venture.

The principal sources of supply for our pipeline systems are regional supply hubs and market centers located in the Gulf Coast region, including offshore Louisiana, the Perryville, Louisiana area, the Henry Hub in Louisiana and the Carthage, Texas area. Our pipelines in the Carthage, Texas area provide access to natural gas supplies from the Bossier Sands, Barnett Shale, Haynesville Shale and other gas producing regions in eastern Texas and northern Louisiana. The Henry Hub serves as the designated delivery point for natural gas futures contracts traded on the New York Mercantile Exchange. Our pipeline systems also have access to unconventional mid-continent supplies such as the Woodford Shale in southeastern Oklahoma and the Fayetteville Shale in Arkansas. We also access the Eagle Ford Shale in southern Texas; wellhead supplies in northern and southern Louisiana and Mississippi; and Canadian natural gas through an unaffiliated pipeline interconnect at Whitesville, Kentucky.

Gulf Crossing: Our Gulf Crossing pipeline system originates near Sherman, Texas, and proceeds to the Perryville, Louisiana area. The market areas are in the Midwest, Northeast, Southeast and Florida through interconnections with Gulf South, Texas Gas and unaffiliated pipelines.

Gulf South: Our Gulf South pipeline system is located along the Gulf Coast in the states of Texas, Louisiana, Mississippi, Alabama and Florida. The on-system markets directly served by the Gulf South system are generally located in eastern Texas, Louisiana, southern Mississippi, southern Alabama, and the Florida Panhandle. These markets include LDCs and municipalities located across the system, including New Orleans, Louisiana;

Jackson, Mississippi; Mobile, Alabama; and Pensacola, Florida, and other end-users located across the system, including the Baton Rouge to New Orleans industrial corridor and Lake Charles, Louisiana. Gulf South also has indirect access to off-system markets through numerous interconnections with unaffiliated interstate and intrastate pipelines and storage facilities. These pipeline interconnections provide access to markets throughout the northeastern and southeastern U.S.

Gulf South has two natural gas storage facilities. The gas storage facility located in Bistineau, Louisiana, has approximately 78.0 Bcf of working gas storage capacity from which Gulf South offers firm and interruptible storage service, including no-notice service. Gulf South's Jackson, Mississippi, gas storage facility has approximately 5.0 Bcf of working gas storage capacity which is used for operational purposes and is not offered for sale to the market.

Texas Gas: Our Texas Gas pipeline system originates in Louisiana, East Texas and Arkansas and runs north and east through Louisiana, Arkansas, Mississippi, Tennessee, Kentucky, Indiana, and into Ohio, with smaller diameter lines extending into Illinois. Texas Gas directly serves LDCs, municipalities and power generators in its market area, which encompasses eight states in the South and Midwest and includes the Memphis, Tennessee; Louisville, Kentucky; Cincinnati and Dayton, Ohio; and Evansville and Indianapolis, Indiana metropolitan areas. Texas Gas also has indirect market access to the Northeast through interconnections with unaffiliated pipelines. A large portion of the gas delivered by the Texas Gas system is used for heating during the winter months, resulting in higher daily throughput.

Texas Gas owns nine natural gas storage fields, of which it owns the majority of the working and base gas. Texas Gas uses this gas to meet the operational requirements of its transportation and storage customers and the requirements of its no-notice service customers. Texas Gas also uses its storage capacity to offer firm and interruptible storage services.

The following table provides information for our pipeline systems as of December 31, 2011:

Pipeline	Miles of Pipeline	Working Gas Storage Capacity (Bcf)	Peak-day Delivery Capacity (Bcf/d)	Average Daily Throughput (Bcf/d)
Gulf Crossing	360	-	1.7	1.2
Gulf South	7,600	83.0	6.9	4.3
Texas Gas	6,100	84.0	4.6	3.2

Field Services: In 2011, we formed our Field Services subsidiary and transferred to it approximately 100 miles of gathering and transmission pipeline. In early 2012 we transferred to Field Services an additional 240 miles of pipeline and two compressor stations. These facilities were modified so that condensate-rich Eagle Ford Shale gas can be accepted into the pipeline. As discussed in more detail below, in addition to operating this pipeline, Field Services is currently developing gathering and processing capabilities in south Texas and Pennsylvania.

Current Expansion Projects

South Texas Eagle Ford Expansion: As discussed above, we have transferred approximately 340 miles of pipeline and two compressor stations to Field Services and modified the pipeline to accept condensate-rich Eagle Ford Shale gas. In February 2012, we announced that Field Services would construct 55 miles of additional gathering pipeline and a cryogenic processing plant in south Texas. This system will have the capability of gathering in excess of 0.3 Bcf per day of liquids rich gas in Karnes and Dewitt counties, which reside in the Eagle Ford Shale production area, and processing up to 150 million cubic feet (MMcf) per day of wet gas. Field Services will also provide re-delivery of processed residue gas to a number of interstate and intrastate pipelines, including Gulf South. The plant and new pipeline are estimated to cost approximately \$180.0 million and are expected to be placed in service in early 2013. We have executed a fixed price contract with Exterran Energy Solutions, L.P. to design, manufacture and construct the processing plant and long-term fee-based gathering and processing agreements with

Statoil Natural Gas LLC and Talisman Energy USA, Inc., under which these customers have committed to approximately 50% of the plant's processing capacity.

Marcellus Gathering System: Field Services and Southwestern Energy Production Company have executed a fifteen year definitive gas gathering agreement which will require construction of a natural gas gathering system in Susquehanna and Lackawanna Counties, Pennsylvania. We will own the gas gathering system that will support Southwestern's development of Marcellus Shale gas. The gathering system, which will have a delivery capacity of approximately 0.3 Bcf/day, will be comprised of approximately 26 miles of twelve-inch high pressure gas pipeline, a low pressure in-field gathering pipeline, compression and dehydration and will interconnect with Tennessee Gas pipeline in Susquehanna County. The project is expected to cost approximately \$90.0 million and the first portion of the system is expected to be placed in service in April 2012.

HP Storage: HP Storage, a joint venture with BPHC of which we own a 20% interest, is in the process of leaching a new salt dome storage cavern which is expected to add working gas capacity of approximately 5.0 Bcf. We expect the additional capacity to be placed in service in the first quarter 2013 and to cost approximately \$35.0 million.

Nature of Contracts

We contract with our customers to provide transportation services and storage services on a firm and interruptible basis. We also provide bundled firm transportation and storage services, which we refer to as no-notice services. In addition, we provide interruptible PAL services.

Transportation Services. We offer transportation services on both a firm and interruptible basis. Our customers choose, based upon their particular needs, the applicable mix of services depending upon availability of pipeline capacity, the price of services and the volume and timing of the customer's requirements. Firm transportation customers reserve a specific amount of pipeline capacity at specified receipt and delivery points on our system. Firm customers generally pay fees based on the quantity of capacity reserved regardless of use, plus a commodity and a fuel charge paid on the volume of gas actually transported. Capacity reservation revenues derived from a firm service contract are generally consistent during the contract term, but can be higher in winter periods than the rest of the year, especially for no-notice service agreements. Firm transportation contracts generally range in term from one to ten years, although we may enter into shorter or longer term contracts. In providing interruptible transportation service, we agree to transport gas for a customer when capacity is available. Interruptible transportation service customers pay a commodity charge only for the volume of gas actually transported, plus a fuel charge. Interruptible transportation agreements have terms ranging from day-to-day to multiple years, with rates that change on a daily, monthly or seasonal basis.

Storage Services. We offer customers storage services on both a firm and interruptible basis. Firm storage customers reserve a specific amount of storage capacity, including injection and withdrawal rights, while interruptible customers receive storage capacity and injection and withdrawal rights when it is available. Similar to firm transportation customers, firm storage customers generally pay fees based on the quantity of capacity reserved plus an injection and withdrawal fee. Firm storage contracts typically range in term from one to ten years. Interruptible storage customers pay for the volume of gas actually stored plus injection and withdrawal fees. Generally, interruptible storage agreements are for monthly terms. FERC has authorized Gulf South to charge market-based rates for its firm and interruptible storage services and Texas Gas is authorized to charge market-based rates for the firm and interruptible storage services associated with approximately 8.3 Bcf of its storage capacity.

No-Notice Services. No-notice services consist of a combination of firm transportation and storage services that allow customers to withdraw gas from storage with little or no notice. Customers pay a reservation charge based upon the capacity reserved plus a commodity and a fuel charge based on the volume of gas actually transported. In accordance with its tariff, Texas Gas loans stored gas to certain of its no-notice customers who are obligated to repay the gas in-kind.

Parking and Lending Service. PAL is an interruptible service offered to customers providing them the ability to park (inject) or borrow (withdraw) gas into or out of our pipeline systems at a specific location for a

specific period of time. Customers pay for PAL service in advance or on a monthly basis depending on the terms of the agreement.

Customers and Markets Served

We transport natural gas for a broad mix of customers, including producers, LDCs, marketers, electric power generators, direct industrial users and interstate and intrastate pipelines, located throughout the Gulf Coast, Midwest and Northeast regions of the U.S.

We contract directly with end-use customers and with producers, marketers and other third parties who provide transportation and storage services to end-users. Based on 2011 revenues, our customer mix was as follows: producers (54%), LDCs (22%), marketers (18%), power generators (5%), and industrial end users and others (1%). Based upon 2011 revenues, our deliveries were as follows: pipeline interconnects (67%), LDCs (18%), storage activities (6%), power generators (4%), industrial end-users (3%), and other (2%). One customer, Devon Gas Services, LP, accounted for approximately 12% of our 2011 operating revenues.

Producers. Producers of natural gas use our services to transport gas supplies from producing areas, primarily from the Gulf Coast region, including shale plays in Texas, Louisiana, Oklahoma and Arkansas, to supply pools and to other customers on and off of our systems. Producers contract with us for storage services to store excess production and to optimize the ultimate sales prices for their gas.

LDCs. Most of our LDC customers use firm transportation services, including no-notice service. We serve approximately 175 LDCs at more than 300 delivery locations across our pipeline systems. The demand of these customers peaks during the winter heating season.

Marketers. Natural gas marketing companies utilize our services to provide services to our other customer groups as well as to customer groups in off-system markets. The services may include combined gas supply management, transportation and storage services to support the needs of the other customer groups. Some of the marketers are sponsored by LDCs or producers.

Power Generators. We are directly connected to 39 natural-gas-fired power generation facilities in ten states. The demand of the power generating customers peaks during the summer cooling season which is counter to the winter season peak demands of the LDCs. Most of our power-generating customers use a combination of no-notice, firm and interruptible transportation services.

Pipelines (off-system). Our pipeline systems serve as feeder pipelines for long-haul interstate pipelines serving markets throughout the midwestern, northeastern and southeastern portions of the U.S. We have numerous interconnects with third-party interstate and intrastate pipelines.

Industrial End Users. We provide approximately 165 industrial facilities with a combination of firm and interruptible transportation services. Our systems are directly connected to industrial facilities in the Baton Rouge to New Orleans industrial corridor; Lake Charles, Louisiana; Mobile, Alabama and Pensacola, Florida. We can also access the Houston Ship Channel through third-party pipelines.

Competition

We compete with numerous other pipelines that provide natural gas transportation and storage services at many locations along our pipeline systems. We also compete with pipelines that are attached to new gas supply sources that are being developed closer to some of our traditional market areas and that customers can access through third-party pipelines. In addition, regulators' continuing efforts to increase competition in the natural gas industry have increased the natural gas transportation options of our traditional customers. As a result of the regulators' policies, segmentation and capacity release have created an active secondary market which increasingly competes with our pipeline services. Further, natural gas competes with other forms of energy available to our customers, including electricity, coal, fuel oils and other alternative fuel sources.

The principal elements of competition among pipelines are available capacity, rates, terms of service, access to gas supplies, flexibility and reliability of service. In many cases, the elements of competition other than pricing, in particular flexibility, terms of service and reliability, are key differentiating factors between competitors. This is especially the case with capacity being sold on a longer-term basis. We are focused on finding opportunities to enhance our competitive profile in these areas by increasing the flexibility of our pipeline systems to meet the demands of customers, such as power generators, and industrial users, and are continually reviewing our services and terms of service to offer customers enhanced service options.

Seasonality

Our revenues can be affected by weather and natural gas price levels and volatility. Weather impacts natural gas demand for heating needs and power generation, which in turn influences the short-term value of transportation and storage across our pipeline systems. Colder than normal winters can result in an increase in the demand for natural gas for heating needs and warmer than normal summers can impact cooling needs, both of which typically result in increased pipeline transportation revenues and throughput. While traditionally peak demand for natural gas occurs during the winter months driven by heating needs, the increased use of natural gas for cooling needs during the summer months has partially reduced the seasonality of our revenues. During 2011, approximately 53% of our revenues and 60% of our operating income, excluding asset impairments and gains and losses on the disposal of operating assets, were recognized in the first and fourth quarters of the year.

Government Regulation

Federal Energy Regulatory Commission. FERC regulates our operating subsidiaries under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. FERC regulates, among other things, the rates and charges for the transportation and storage of natural gas in interstate commerce and the extension, enlargement or abandonment of facilities under its jurisdiction. Where required, our operating subsidiaries hold certificates of public convenience and necessity issued by FERC covering certain of their facilities, activities and services. FERC also prescribes accounting treatment for our operating subsidiaries which is separately reported pursuant to forms filed with FERC. The regulatory books and records and other activities of our operating subsidiaries may be periodically audited by FERC.

The maximum rates that may be charged by our operating subsidiaries for all aspects of the gas transportation services we provide are established through FERC's cost-of-service rate-making process. The maximum rates that may be charged by us for storage services on Texas Gas, with the exception of services associated with a portion of the working gas capacity on that system, are also established through FERC's cost-of-service rate-making process. Key determinants in FERC's cost-of-service rate-making process are the costs of providing service, the volumes of gas being transported, the rate design, the allocation of costs between services, the capital structure and the rate of return a pipeline is permitted to earn. FERC has authorized Gulf South to charge market-based rates for its firm and interruptible storage. Texas Gas is authorized to charge market-based rates for the firm and interruptible storage services associated with approximately 8.3 Bcf of its storage capacity. Neither Gulf South nor Texas Gas has an obligation to file a new rate case. In January 2012, Gulf Crossing filed with FERC a cost-and-revenue study to justify its rates as mandated in the initial order approving the construction and operation of that pipeline. Although FERC could open a proceeding under Section 5 of the Natural Gas Act to review our rates in response to the filing, the outcome of this filing is not expected to have a material impact on our business, financial condition, results of operations or cash flows.

U.S. Department of Transportation (DOT). We are regulated by DOT under the Natural Gas Pipeline Safety Act of 1968, as amended by Title I of the Pipeline Safety Act of 1979, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas pipelines. We have received authority from the Pipeline and Hazardous Materials Safety Administration (PHMSA), an agency of DOT, to operate certain pipeline assets under special permits that will allow us to operate those pipeline assets at higher than normal operating pressures of up to 0.80 of the pipe's Specified Minimum Yield Strength (SMYS). Operating at higher than normal operating pressures will allow us to transport all of the volumes we have contracted for with our customers. PHMSA retains discretion whether to grant or maintain authority for us to operate our pipeline assets at higher pressures. PHMSA has also developed regulations that require transportation pipeline operators to implement integrity management programs to comprehensively evaluate certain areas along our pipelines and take additional

measures to protect pipeline segments located in highly populated areas. A recently enacted pipeline safety bill could result in increased regulatory requirements.

Other. Our operations are also subject to extensive federal, state, and local laws and regulations relating to protection of the environment. Such regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances into the environment. Environmental regulations also require that our facilities, sites and other properties be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. These laws include, for example:

- the Clean Air Act and analogous state laws which impose obligations related to air emissions, including, in the case of the Clean Air Act, greenhouse gas emissions and regulations affecting reciprocating engines subject to Maximum Achievable Control Technology (MACT) standards;
- the Water Pollution Control Act, commonly referred to as the Clean Water Act, and analogous state laws which regulate discharge of wastewaters from our facilities into state and federal waters;
- the Comprehensive Environmental Response, Compensation and Liability Act, commonly referred to as CERCLA, or the Superfund law, and analogous state laws which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal; and
- the Resource Conservation and Recovery Act, and analogous state laws which impose requirements for the handling and discharge of solid and hazardous waste from our facilities.

Effects of Compliance with Environmental Regulations

Note 3 in Item 8 of this Report contains information regarding environmental compliance.

Employee Relations

At December 31, 2011, we had approximately 1,170 employees, approximately 115 of whom are included in collective bargaining units. A satisfactory relationship exists between management and labor. We maintain various defined contribution plans covering substantially all of our employees and various other plans which provide regular active employees with group life, hospital, and medical benefits, as well as disability benefits. We also have a non-contributory, defined benefit pension plan and a postretirement medical plan which covers Texas Gas employees hired prior to certain dates. Note 9 in Item 8 of this Report contains further information regarding our employee benefits.

Available Information

Our website is located at www.bwpmlp.com. We make available free of charge through our website our annual reports on Form 10-K, which include our audited financial statements, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as we electronically file such material with the Securities and Exchange Commission (SEC). These documents are also available at the SEC's website at www.sec.gov. Additionally, copies of these documents, excluding exhibits, may be requested at no cost by contacting Investor Relations, Boardwalk Pipeline Partners, LP, 9 Greenway Plaza, Suite 2800, Houston, TX 77046.

We also make available within the "Governance" section of our website our corporate governance guidelines, the charter of our Audit Committee and our Code of Business Conduct and Ethics. Requests for copies may be directed in writing to: Boardwalk Pipeline Partners, LP, 9 Greenway Plaza, Suite 2800, Houston, TX 77046, Attention: Corporate Secretary.

Interested parties may contact the chairpersons of any of our Board committees, our Board's independent directors as a group or our full Board in writing by mail to Boardwalk Pipeline Partners, LP, 9 Greenway Plaza, Suite 2800, Houston, TX 77046, Attention: Corporate Secretary. All such communications will be delivered to the director or directors to whom they are addressed.

Item 1A. Risk Factors

Our business faces many risks. We have described below the material risks which we and our subsidiaries face. Each of the risks and uncertainties described below could lead to events or circumstances that may have a material adverse effect on our business, financial condition, results of operations or cash flows, including our ability to make distributions to our unitholders.

All of the information included in this report and any subsequent reports we may file with the SEC or make available to the public should be carefully considered and evaluated before investing in any securities issued by us.

Business Risks

We may not be able to maintain or replace expiring gas transportation and storage contracts at attractive rates or on a long-term basis.

We are exposed to market risk when our transportation contracts expire and need to be renewed or replaced. We may not be able to extend contracts with existing customers or obtain replacement contracts at attractive rates or on a long-term basis. Key drivers that influence the rates and terms of our transportation contracts include the current and anticipated basis differentials between physical locations on our pipeline systems, which can be affected by, among other things, the availability and supply of natural gas, competition from other pipelines, including pipelines under development, available capacity, storage inventories, regulatory developments, weather and general market demand in the respective areas. The new sources of natural gas that have been identified throughout the U.S. have created changes in pricing dynamics between supply basins, pooling points and market areas. As a result of the increase in overall pipeline capacity and the new sources of supply, basis spreads on our pipeline systems have narrowed over the past several years. Basis spreads have impacted, and will continue to impact, the rates we can negotiate with our customers on contracts due for renewal for our firm transportation services, especially the rates we are able to charge for our interruptible and short-term firm transportation services.

Continued development of new supply sources impacts demand for our services.

Supplies of natural gas in production areas that are closer to key end-user market areas than our supply sources may compete with gas originating in production areas connected to our system. For example, the Marcellus Shale in Pennsylvania, New York, West Virginia and Ohio, may cause gas in supply areas connected to our system to be diverted to market areas other than our traditional market areas and may adversely affect capacity utilization on our systems and our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows. In addition, natural gas supplies from the Rocky Mountains and Canada may compete with and displace volumes from Gulf Coast and Mid-Continent supply sources where we are located, which may also adversely affect our transportation volumes and the rates we can charge for our services.

We depend on certain key customers for a significant portion of our revenues. The loss of any of these key customers could result in a decline in our revenues.

We rely on a limited number of customers for a significant portion of revenues. Our largest customer in terms of revenue, Devon Gas Services, LP, represented over 12% of our 2011 revenues and we expect this customer to account for more than 10% of our 2012 revenues. Our top ten customers comprised approximately 47% of our revenues in 2011. We may be unable to negotiate extensions or replacements of contracts with key customers on favorable terms which could materially reduce our contracted transportation volumes and the rates we can charge for our services.

We are exposed to credit risk relating to nonperformance by our customers.

Credit risk relates to the risk of loss resulting from the nonperformance by a customer of its contractual obligations. Our exposure generally relates to receivables for services provided, future performance under firm agreements and volumes of gas owed by customers for imbalances or gas loaned by us to them under certain no-notice and PAL services. Our FERC gas tariffs only allow us to require limited credit support in the event that our transportation customers are unable to pay for our services. If any of our significant customers have credit or

financial problems which result in a delay or failure to pay for services provided by us or contracted for with us, or to repay the gas they owe us, it could have a material adverse effect on our business. In addition, as contracts expire, the credit or financial failure of any of our customers could also result in the non-renewal of contracted capacity, which could have a material adverse effect on our business. Item 7A of this Report contains more information on credit risk arising from gas loaned to customers.

We may incur higher than expected costs to maintain our pipeline systems.

We incur substantial costs for ongoing maintenance of our pipeline systems and related facilities, some of which reflect increased regulatory requirements applicable to all interstate pipelines, including the pipeline integrity programs monitored by PHMSA. These costs may be capitalized or expensed, depending on the nature of the activity, and include those incurred for pipeline integrity management activities, equipment overhauls, general maintenance and repairs. Although we expect to complete the implementation of our current pipeline integrity program by the end of 2012, we could continue to incur substantial capital and operating expenditures beyond 2012 relating to the integrity and safety of our pipelines. In addition, there is a risk that new regulations associated with pipeline safety and integrity issues will be adopted that could require us to incur additional expenditures in the future.

We continue to pursue complex expansion projects which involve significant risks.

We may undertake large development projects in the future as we continue to pursue our growth strategy, including projects in new market areas or product lines. The successful completion of such projects, and the returns we may realize from those projects after completion, are subject to many significant risks, including cost overruns; delays in obtaining regulatory approvals; difficult construction conditions, including adverse weather conditions; delays in obtaining key materials; shortages of qualified labor; and escalating costs of labor and materials, particularly in the event there is a high level of construction activity in the pipeline industry at that time. As a result, we may not be able to complete future projects on the expected terms, cost or schedule, or at all. In addition, we cannot be certain that, if completed, we will be able to operate these projects, or that they will perform, in accordance with our expectations. Other areas of our business may suffer as a result of the diversion of our management's attention and other resources from our other business concerns to our projects. Any of these factors could impair our ability to realize the benefits we had anticipated from the projects.

Our future growth could be limited.

During the past several years, we completed a number of large development projects to enlarge and enhance our pipeline and storage systems. We plan to continue to grow and diversify our business by among other things, investing in new assets through acquisition, developing a broader midstream service capability and accessing new markets such as the Marcellus Shale. Our ability to grow, diversify and increase distributable cash flow per unit will depend, in part, on our ability to close and execute on accretive projects. We might not complete these large projects for any of the following reasons:

- inability to identify opportunities with favorable projected financial returns;
- inefficiencies and complexities that can occur because of unfamiliarity with new product lines or new markets;
- inability to raise financing for identified opportunities; or
- inability to secure sufficient commitments from potential customers due to competition from other companies or for other reasons.

We compete with other natural gas pipelines.

The principal elements of competition among pipelines are availability of capacity, rates, terms of service, access to gas supplies, flexibility and reliability of service. Additionally, FERC's policies promote competition in natural gas markets by increasing the number of gas transportation options available to our customer base. Increased competition could reduce the volumes of gas transported by our pipeline systems or, in instances where we do not have long-term contracts with fixed rates, could cause us to decrease the transportation or storage rates charged to our customers. Competition could intensify the negative impact of factors that could significantly decrease demand

for natural gas in the markets served by our operating subsidiaries, such as a recession or adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of natural gas.

Significant changes in energy prices could affect natural gas market supply and demand, or potentially reduce the competitiveness of natural gas compared with other forms of energy available to our customers, which could reduce system throughput and adversely affect our revenues and available cash.

We are currently experiencing extraordinarily low natural gas prices, which are being driven by the abundance of supply and increased infrastructure. Due to the natural decline in traditional gas production connected to our system, our success depends on our ability to obtain access to new sources of natural gas, which is dependent on factors beyond our control including the price level of natural gas. In general terms, the price of natural gas fluctuates in response to changes in supply and demand, market uncertainty and a variety of additional factors, including:

- worldwide economic conditions;
- weather conditions, seasonal trends and hurricane disruptions;
- the relationship between the available supplies and the demand for natural gas;
- new supply sources;
- the availability of adequate transportation capacity;
- storage inventory levels;
- the price and availability of other forms of energy;
- the effect of energy conservation measures;
- the nature and extent of, and changes in, governmental regulation, for example greenhouse gas legislation and taxation; and
- the anticipated future prices of natural gas and other commodities.

It is difficult to predict future changes in gas prices. However, the abundance of natural gas supply discoveries over the last few years and global economic slowdown would generally indicate a bias toward downward pressure on prices. Downward movement in gas prices could negatively impact producers in nontraditional supply areas such as the Barnett Shale, the Bossier Sands, the Woodford Shale, the Fayetteville Shale and the Haynesville Shale, including producers who have contracted for capacity with us. Significant financial difficulties experienced by our producer customers could impact their ability to pay for services rendered or otherwise reduce their demand for our services.

High natural gas prices may result in a reduction in the demand for natural gas. A reduced level of demand for natural gas could reduce the utilization of capacity on our systems, reduce the demand for our services and could result in the non-renewal of contracted capacity as contracts expire.

A significant portion of our debt will mature over the next twelve to eighteen months.

Our revolving credit facility, \$225.0 million of 5.75% senior unsecured Gulf South notes and \$100.0 million of subordinated loans with BPHC are due to mature in 2012. While we expect to refinance this indebtedness prior to or upon maturity, we may not be able to refinance this indebtedness or refinancing may not be available on commercially reasonable terms. The financial terms or covenants of the new credit facility or any other indebtedness may not be as favorable as those under our existing indebtedness.

Our revolving credit facility contains operating and financial covenants that restrict our business and financing activities.

Our revolving credit facility contains operating and financial covenants that may restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. For example, our credit

agreement limits our ability to make loans or investments, make material changes to the nature of our business, merge, consolidate or engage in asset sales, or grant liens or make negative pledges. The agreement also requires us to maintain a ratio of consolidated debt to consolidated earnings before interest, taxes, depreciation and amortization (as defined in the agreement) of no more than five to one, which limits the amount of additional indebtedness we can incur. Future financing agreements we may enter into may contain similar or more restrictive covenants.

Our ability to comply with the covenants and restrictions contained in our credit agreement may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions or our financial performance deteriorate, our ability to comply with these covenants may be impaired. If we are not able to incur additional indebtedness we may need to sell additional equity securities to raise needed capital, which would be dilutive to our existing equity holders. If we default under our credit agreement or another financing agreement, significant additional restrictions may become applicable, including a restriction on our ability to make distributions to unitholders. In addition, a default could result in a significant portion of our indebtedness becoming immediately due and payable, and our lenders could terminate their commitment to make further loans to us. In such event, we would not have, and may not be able to obtain, sufficient funds to make these accelerated payments.

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

There are a variety of operating risks inherent in our natural gas transportation and storage operations such as leaks, explosions, fires and mechanical problems. Additionally, the nature and location of our business may make us susceptible to catastrophic losses from hurricanes or other named storms, particularly with regard to our assets in the Gulf Coast region, windstorms, earthquakes, hail, explosions, severe winter weather and fires. Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial financial losses. The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from some of these risks.

We currently possess property, business interruption and general liability insurance, but proceeds from such insurance coverage may not be adequate for all liabilities or expenses incurred or revenues lost. Moreover, such insurance may not be available in the future at commercially reasonable costs and terms. The insurance coverage we do obtain may contain large deductibles or fail to cover certain hazards or all potential losses.

Possible terrorist activities or military actions could adversely affect our business.

The continued threat of terrorism and the impact of retaliatory military and other action by the U.S. and its allies might lead to increased political, economic and financial market instability and volatility in prices for natural gas, which could affect the markets for our natural gas transportation and storage services. While we are taking steps that we believe are appropriate to increase the security of our assets, we may not be able to completely secure our assets, completely protect them against a terrorist attack or obtain adequate insurance coverage for terrorist acts at reasonable rates.

Regulatory Risks

We need to maintain authority from PHMSA to operate portions of our pipeline systems at higher than normal operating pressures.

We have entered into firm transportation contracts with shippers which utilize the design capacity of certain of our pipeline assets, assuming that we operate those pipeline assets at higher than normal operating pressures (up to 0.80 SMYS). We have authority from PHMSA to operate those pipeline assets at such higher pressures, however PHMSA retains discretion to withdraw or modify this authority. If PHMSA were to withdraw or materially modify such authority, we may not be able to transport all of our contracted quantities of natural gas on our pipeline assets and could incur significant additional costs to re-obtain such authority or to develop alternate ways to meet our contractual obligations.

Our natural gas transportation and storage operations are subject to FERC's rate-making policies which could limit our ability to recover the full cost of operating our pipelines, including earning a reasonable return.

We are subject to extensive regulations relating to the rates we can charge for our transportation and storage operations. For our cost-based services, FERC establishes both the maximum and minimum rates we can charge. The basic elements that FERC considers are the costs of providing service, the volumes of gas being transported, the rate design, the allocation of costs between services, the capital structure and the rate of return a pipeline is permitted to earn. We may not be able to recover all of our costs through existing or future rates.

Customers or FERC can challenge the existing rates on any of our pipelines. Such a challenge against us could adversely affect our ability to establish reasonable transportation rates, to charge rates that would cover future increases in our costs or even to continue to collect rates to maintain our current revenue levels that are designed to permit a reasonable opportunity to recover current costs and depreciation and earn a reasonable return.

If any of our pipelines were to file a rate case, or if they have to defend their rates in a proceeding commenced by a customer or FERC, we would be required, among other things, to establish that the inclusion of an income tax allowance in our cost of service is just and reasonable. Under current FERC policy, since we are a limited partnership and do not pay U.S. federal income taxes, this would require us to show that our unitholders (or their ultimate owners) are subject to federal income taxation. To support such a showing, our general partner may elect to require owners of our units to re-certify their status as being subject to U.S. federal income taxation on the income generated by us or we may attempt to provide other evidence. We can provide no assurance that the evidence we might provide to FERC will be sufficient to establish that our unitholders (or their ultimate owners) are subject to U.S. federal income tax liability on the income generated by our jurisdictional pipelines. If we are unable to make such a showing, FERC could disallow a substantial portion of the income tax allowance included in the determination of the maximum rates that may be charged by our pipelines, which could result in a reduction of such maximum rates from current levels.

We are subject to extensive regulation by FERC, PHMSA and others, in addition to FERC rules and regulations related to the rates we can charge for our services.

Our business operations are subject to extensive regulation by FERC, including with respect to the types and terms of services we may offer to our customers, construction of new facilities, creation, modification or abandonment of services or facilities, recordkeeping and relationships with affiliated companies. FERC action in any of these areas could adversely affect our ability to compete for business, construct new facilities, offer new services or recover the full cost of operating our pipelines. This regulatory oversight can result in longer lead times to develop and complete any future project. The federal regulatory approval and compliance process could raise the costs of such projects to the point where they are no longer sufficiently timely or cost competitive when compared to competing projects that are not subject to the federal regulatory regime.

We are also subject to strict safety regulations imposed by PHMSA, including those requiring us to develop and maintain integrity management programs to comprehensively evaluate certain areas along our pipelines and take additional measures to protect pipeline segments located in what are referred to as high consequence areas where a leak or rupture could potentially do the most harm. In the past several years, there have been several integrity-related incidents on pipelines not affiliated with us that could lead to increased regulation of natural gas pipelines by PHMSA. Regulations, changes to regulations or an increase in public expectations for pipeline safety may require additional reporting, the replacement of some of our pipeline segments, the addition of monitoring equipment and more frequent inspection or testing of our pipeline facilities. Any repair, remediation, preventative or mitigating actions may require significant capital and operating expenditures.

Our operations are also subject to extensive federal, state and local laws and regulations relating to protection of the environment. These laws include, for example, the Clean Air Act, the Water Pollution Control Act, commonly referred to as the Clean Water Act, CERCLA or the Superfund law, the Resource Conservation and Recovery Act and analogous state laws. The existing environmental regulations could be revised or reinterpreted in the future and new laws and regulations could be adopted or become applicable to our operations or facilities. Compliance with current and future laws and regulations could require significant expenditures or we could be

delayed in or prevented from obtaining required environmental regulatory approvals for certain projects, which could require us to shut down certain facilities or pay additional costs.

Should we fail to comply with all applicable laws and regulations, we could also be subject to penalties and fines and/or otherwise incur significant costs to restore compliance.

We face risks associated with global climate change.

In 2009, the Environmental Protection Agency, (EPA) made a determination that greenhouse gases are a threat to the public health and the environment and may be regulated as “air pollutants” under the Clean Air Act (CAA). In 2011, we began filing reports with the EPA regarding greenhouse gas emissions from our compressor stations, pursuant to final rules issued by the EPA regarding the reporting of greenhouse gas emissions from sources in the U.S. that annually emit 25,000 or more metric tons of greenhouse gases, including carbon dioxide, methane and others. Additionally, we conducted various facility surveys across our entire system to comply with the EPA’s greenhouse gas emission calculations and reporting regulations and will continue to do so annually as required by the rule. Additional government or legislative action may be initiated to reduce greenhouse gas emissions along with other government actions that may have the effect of requiring or encouraging reduced consumption or production of natural gas. Some states have also adopted laws regulating greenhouse gas emissions, although none of the states in which we operate have adopted such laws.

Federal legislation, which could consist of an emissions cap and trade system, may be enacted in the U.S. in the near future. Depending on the particular regulation adopted, we could be required to purchase and surrender allowances for greenhouse gas emissions resulting from our operations (for example, our compressor units). In addition, compliance with any new federal or state laws and regulations requiring adoption of greenhouse gas control programs or imposing restrictions on emissions of carbon dioxide in areas of the U.S. in which we conduct business could adversely affect the demand for and the cost to produce and transport natural gas which would adversely affect our business.

Partnership Structure Risks

Our general partner and its affiliates own a controlling interest in us, have conflicts of interest and owe us only limited fiduciary duties, which may permit them to favor their own interests.

BPHC, a wholly-owned subsidiary of Loews, owns approximately 61% of our equity interests, excluding the IDRs, and owns and controls our general partner, which controls us. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to BPHC. Furthermore, certain directors and officers of our general partner are also directors or officers of affiliates of our general partner. Conflicts of interest may arise between BPHC and its subsidiaries, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These potential conflicts include, among others, the following situations:

- BPHC and its affiliates may engage in competition with us;
- neither our partnership agreement nor any other agreement requires BPHC or its affiliates (other than our general partner) to pursue a business strategy that favors us. Directors and officers of BPHC and its affiliates have a fiduciary duty to make decisions in the best interest of BPHC shareholders, which may be contrary to our interests;
- our general partner is allowed to take into account the interests of parties other than us, such as BPHC and its affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;
- some officers of our general partner who provide services to us may devote time to affiliates of our general partner and may be compensated for services rendered to such affiliates;

- our partnership agreement limits the liability and reduces the fiduciary duties of our general partner and the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing common units, unitholders are consenting to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, repayments of indebtedness, issuances of additional partnership securities and cash reserves, each of which can affect the amount of cash that is available for distribution to our unitholders;
- our general partner determines the amount and timing of any capital expenditures and whether an expenditure is for maintenance capital, which reduces operating surplus, or a capital improvement expenditure, which does not. Such determination can affect the amount of cash that is distributed to our unitholders;
- in some instances, our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions;
- our general partner determines which costs, including allocated overhead, incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf, and provides that reimbursement to Loews for amounts allocable to us consistent with accounting and allocation methodologies generally permitted by FERC for rate-making purposes and past business practices is deemed fair and reasonable to us;
- our general partner controls the enforcement of obligations owed to us by it and its affiliates;
- our general partner intends to limit its liability regarding our contractual obligations;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our general partner may exercise its rights to call and purchase (1) all of our common units if, at any time, it and its affiliates own more than 80% of the outstanding common units or (2) all of our equity securities (including common units), if it and its affiliates own more than 50% in the aggregate of the outstanding common units and any other classes of equity securities and it receives an opinion of outside legal counsel to the effect that our being a pass-through entity for tax purposes has or is reasonably likely to have a material adverse effect on the maximum applicable rates we can charge our customers.

Our partnership agreement limits our general partner's fiduciary duties to unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting us, our affiliates or any limited partner. Decisions made by our general partner in its individual capacity will be made by a majority of the owners of our general partner, and not by the board of directors of our general partner. Examples of these kinds of decisions include the exercise of its call rights, its voting rights with respect to the units it owns and its registration rights and the determination of whether to consent to any merger or consolidation of the partnership;
- provides that our general partner shall not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith, meaning it believed that the decisions were in the best interests of the partnership;

- generally provides that affiliate transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally provided to or available from unrelated third parties or be “fair and reasonable” to us and that, in determining whether a transaction or resolution is “fair and reasonable,” our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and
- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets, which may affect our ability to make distributions.

We are a partnership holding company and our operating subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in our subsidiaries. As a result, our ability to make distributions to our unitholders depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies.

Tax Risks

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 if we were to become subject to additional amounts of entity-level taxation for state tax purposes, then our cash distributions to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. 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 additional state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in the anticipated cash flows and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Current tax law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to additional amounts of entity-level taxation for state tax purposes. For example, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. Imposition of such a tax on us would reduce the cash available for distribution to unitholders.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to a material amount of entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

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

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by legislative, judicial or administrative changes and differing interpretations at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Recently, members of Congress have considered substantive changes to the existing U.S. tax laws that would affect certain publicly traded partnerships. Although it does not appear that the legislation considered would have affected our tax treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will be reconsidered or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted, and the costs of any contest will reduce our cash distributions to our unitholders.

The IRS has not made determinations with respect to all the federal income tax matters affecting us or our unitholders. The IRS may adopt positions that differ from the positions that we take. Therefore, it may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take and even then 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 common units and the price at which they trade. In addition, because the costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner, any such contest will result in a reduction in cash available for distribution.

Our unitholders may be required to pay taxes on their share of our income even if such unitholders do not receive any cash distributions from us.

Our unitholders will be treated as partners to whom we will allocate taxable income and who will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not such unitholders receive cash distributions from us. Our unitholders may not receive cash distributions from us equal to such unitholders' share of our taxable income or even equal to the actual tax liability that results from such unitholders' share of our taxable income.

Tax gain or loss on the disposition of our common units could be different than expected.

If our unitholders sell their common units, such unitholders will recognize gain or loss equal to the difference between the amount realized and such unitholders' tax basis in those common units. Distributions in excess of our unitholders' allocable share of our net taxable income decrease their tax basis in their common units. Accordingly, to the extent a unitholder's distributions have exceeded such unitholder's allocable share of our net taxable income, the sale of units by such unitholder will produce taxable income to them if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing a gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if our unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as 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 could 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 U.S. 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 common units.

We will treat each purchaser of common units as having the same tax benefits without regard to the actual common units purchased. The IRS may challenge this treatment, which could result in a decrease in the value of the common units.

Because we cannot match transferors and transferees of common units we will adopt depreciation and amortization positions that may not conform with all aspects of existing Treasury Regulations. These positions may result in an understatement of deductions and an overstatement of income to our unitholders. A successful IRS challenge to those positions could decrease the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from any sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular 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 units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, however, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. 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 units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those 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 units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders’ sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders’ tax returns without the benefit of additional deductions.

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

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in our filing two tax returns for one fiscal year, and may 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 calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for tax purposes. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred. The IRS has recently announced a relief procedure whereby a publicly traded partnership that has technically terminated may be permitted to provide only a single Schedule K-1 to unitholders for the two tax years within the fiscal year which the termination occurs.

Our unitholders may be subject to state and local taxes and return filing requirements as a result of investing in our common units.

In addition to federal income taxes, unitholders 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 our unitholders do not reside in any of those jurisdictions. Our unitholders 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, unitholders may be subject to penalties for failure to comply with those requirements. We conduct business in twelve states. We may own property or conduct business in other states or foreign countries in the future. It is our unitholders' responsibility to file all federal, state and local tax returns.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We are headquartered in approximately 108,000 square feet of leased office space located in Houston, Texas. We also have approximately 108,000 square feet of office space in Owensboro, Kentucky, in a building that we own. Our operating subsidiaries own their respective pipeline systems in fee. However, substantial portions of these systems are constructed and maintained on property owned by others pursuant to rights-of-way, easements, permits, licenses or consents.

Our Pipeline and Storage Systems, in Item 1 of this Report contains additional information regarding our material property, including our pipelines and storage facilities.

Item 3. Legal Proceedings

None.

Item 4. Mine Safety Disclosures

None.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our Partnership Interests

As of December 31, 2011, we had outstanding 175.7 million common units, 22.9 million class B units, a 2% general partner interest and IDRs. Subsequent to December 31, 2011, we issued an additional 9.2 million common units to the public, increasing our outstanding common units to 184.9 million. The common units and class B units together represent all of our limited partner interests and 98% of our total ownership interests, in each case excluding our IDRs. As discussed below under *Our Cash Distribution Policy—Incentive Distribution Rights*, the IDRs represent the right for the holder to receive varying percentages of quarterly distributions of available cash from operating surplus in excess of certain specified target quarterly distribution levels. As such, the IDRs cannot be expressed as a constant percentage of our total ownership interests.

BPHC, a wholly-owned subsidiary of Loews, owns 102.7 million of our common units, all 22.9 million of our class B units and, through Boardwalk GP, LP, an indirect wholly-owned subsidiary of BPHC, holds the 2% general partner interest and all of the IDRs. As of February 21, 2012, the common units, class B units and general partner interest held by BPHC represent approximately 61% of our equity interests, excluding IDRs. The additional interest represented by the IDRs is not included in such ownership percentage because, as noted above, the IDRs cannot be expressed as a constant percentage of our ownership.

Market Information

As of February 17, 2012, we had 184.9 million common units outstanding held by approximately 56 holders of record. Our common units are traded on the NYSE under the symbol “BWP.”

The following table sets forth, for the periods indicated, the high and low sales prices for our common units, as reported on the NYSE Composite Transactions Tape, and information regarding our quarterly distributions. The closing sales price of our common units on the NYSE on February 17, 2012, was \$27.05 per unit.

	Sales Price Range per Common Unit		Cash Distributions per Common Unit
	High	Low	(1) (2)
Year ended December 31, 2011:			
Fourth quarter	\$ 29.12	\$ 23.82	\$ 0.5300
Third quarter	29.32	23.54	0.5275
Second quarter	33.47	27.01	0.5250
First quarter	33.50	31.01	0.5225
Year ended December 31, 2010:			
Fourth quarter	\$ 34.23	\$ 29.80	\$ 0.520
Third quarter	32.72	29.51	0.515
Second quarter	30.57	14.49	0.510
First quarter	31.44	28.26	0.505

- (1) Represents cash distributions attributable to the quarter and declared and paid to limited partner unitholders within 60 days after quarter end.
- (2) We also paid cash distributions to our general partner with respect to its 2% general partner interest and, with respect to that portion of the distribution in excess of \$0.4025 per unit, its IDRs described below. The class B unitholder participates in distributions on a pari passu basis with our common units up to \$0.30 per quarter. The class B units

do not participate in quarterly distributions above \$0.30 per unit.

Our Cash Distribution Policy

Our cash distribution policy is consistent with the terms of our partnership agreement which requires us to distribute our “available cash,” as that term is defined in our partnership agreement, on a quarterly basis. However, there is no guarantee that unitholders will receive quarterly distributions from us. Our distribution policy may be changed at any time and is subject to certain restrictions or limitations, including, among others, our general partner’s broad discretion to establish reserves which could reduce cash available for distributions, FERC regulations which place restrictions on various types of cash management programs employed by companies in the energy industry, including our operating subsidiaries, the requirements of applicable state partnership and limited liability company laws, and the requirements of our revolving credit facility which would prohibit us from making distributions to unitholders if an event of default were to occur. In addition, we may lack sufficient cash to pay distributions to unitholders due to a number of factors, including those described in Item 1A, *Risk Factors*, of this Report.

Incentive Distribution Rights

IDRs represent a limited partner ownership interest and include the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the target distribution levels have been achieved, as defined in our partnership agreement. Our general partner currently holds all of our IDRs, but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement. In 2011, 2010 and 2009, we paid \$22.3 million, \$18.2 million and \$13.3 million in distributions on behalf of our IDRs. Note 10 in Item 8 of this Report contains more information regarding our distributions.

Assuming we do not issue any additional classes of units and our general partner maintains its 2% general partner interest, we will distribute any available cash from operating surplus for that quarter among the unitholders and our general partner as follows:

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
		Limited Partner Unitholders	General Partner and IDRs
	Target Amount	(1)	
First Target Distribution	up to \$0.4025	98%	2%
Second Target Distribution	above \$0.4025 up to \$0.4375	85%	15%
Third Target Distribution	above \$0.4375 up to \$0.5250	75%	25%
Thereafter	above \$0.5250	50%	50%

- (1) Distributions to our limited partner unitholders include distributions on behalf of our class B units. The class B units share in quarterly distributions of available cash from operating surplus on a pari passu basis with our common units, until each common unit and class B unit has received a quarterly distribution of \$0.30. The class B units do not participate in quarterly distributions above \$0.30 per unit.

Equity Compensation Plans

For information about our equity compensation plans, see *Securities Authorized for Issuance under Equity Compensation Plans* in Item 12 of this Report.

Issuer Purchases of Equity Securities

None.

Item 6. Selected Financial Data

The following table presents our selected historical financial and operating data. As used herein, EBITDA means earnings before interest, income taxes, depreciation and amortization. EBITDA and distributable cash flow are not calculated or presented in accordance with accounting principles generally accepted in the U.S. (GAAP). We explain these measures below and reconcile them to the most directly comparable financial measures calculated and presented in accordance with GAAP in (3) *Non-GAAP Financial Measures*. The financial data below should be read in conjunction with the Consolidated Financial Statements and Notes thereto included in Item 8 of this Report (in millions, except Net income per common unit, Net income per class B unit, Net income per subordinated unit, Distributions per common unit and Distributions per Class B unit):

	For the Year Ended December 31,				
	2011	2010	2009	2008	2007
Total operating revenues	\$ 1,138.8	\$ 1,116.8	\$ 909.2	\$ 784.8	\$ 643.2
Net income	220.0	289.4	162.7	294.0	227.7
Total assets	6,770.6	6,878.0	6,895.8	6,721.6	4,122.0
Long-term debt	3,198.7	3,252.3	3,100.0	2,889.4	1,847.9
Net income per common unit	1.09	1.47	0.88	2.09	1.91
Net income per class B unit ⁽¹⁾	0.14	0.62	0.08	0.60	-
Net income per subordinated unit ⁽¹⁾	-	-	-	1.68	1.86
Distributions per common unit ⁽²⁾	2.095	2.030	1.950	1.870	1.740
Distributions per class B unit ⁽¹⁾	1.20	1.20	1.20	0.30	-
EBITDA ⁽³⁾	617.7	658.2	498.0	474.6	349.8
Distributable cash flow ⁽³⁾	390.9	454.3	314.3	385.3	272.8

- (1) In June 2008, we issued and sold approximately 22.9 million class B units. These class B units began sharing in earnings allocations on July 1, 2008 and began participating in distributions with the distribution attributable to the third quarter 2008. In November 2008, all of the 33.1 million subordinated units converted to common units.
- (2) Distributions per subordinated unit were the same as the distributions per common unit for the years ended December 31, 2008 and 2007.
- (3) Non-GAAP Financial Measures

We use non-GAAP measures to evaluate our business and performance, including EBITDA and distributable cash flow. EBITDA is used as a supplemental financial measure by management and by external users of our financial statements, such as investors, commercial banks, research analysts and rating agencies, to assess:

- our financial performance without regard to financing methods, capital structure or historical cost basis;
- our ability to generate cash sufficient to pay interest on our indebtedness and to make distributions to our partners;
- our operating performance and return on invested capital as compared to those of other companies in the natural gas transportation, gathering and storage business, without regard to financing methods and capital structure; and
- the viability of acquisitions and capital expenditure projects.

Distributable cash flow is used as a supplemental measure by management and by external users of our financial statements, as defined above, to assess our ability to make cash distributions to our unitholders and our general partner.

EBITDA and distributable cash flow should not be considered alternatives to, or more meaningful than, net income, operating income, cash flows from operating activities or any

other measure of financial performance or liquidity presented in accordance with GAAP, or as indicators of our operating performance or liquidity. Certain items excluded from EBITDA and distributable cash flow are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as historic costs of depreciable assets. We have included information concerning EBITDA because EBITDA provides additional information as to our ability to meet our fixed charges and is presented solely as a supplemental measure. Likewise, we have included information concerning distributable cash flow as a supplemental financial measure we use to assess our ability to make distributions to our unitholders and general partner. However, viewing EBITDA and distributable cash flow as indicators of our ability to make cash distributions on our common units should be done with caution, as we might be required to conserve funds or to allocate funds to business or legal purposes other than making distributions. EBITDA and distributable cash flow are not necessarily comparable to similarly titled measures of another company.

The following table presents a reconciliation of EBITDA and distributable cash flow to net income, the most directly comparable GAAP financial measure for each of the periods presented below (in millions):

	For the Year Ended December 31,				
	2011	2010	2009	2008	2007
Net income	\$ 220.0	\$ 289.4	\$ 162.7	\$ 294.0	\$ 227.7
Income taxes	0.4	0.5	0.3	1.0	0.8
Depreciation and amortization	225.2	217.9	203.1	124.8	81.8
Interest expense	159.3	151.0	132.1	57.7	61.0
Interest income	(0.4)	(0.6)	(0.2)	(2.9)	(21.5)
Loss on debt extinguishment	13.2	-	-	-	-
EBITDA	<u>\$ 617.7</u>	<u>\$ 658.2</u>	<u>\$ 498.0</u>	<u>\$ 474.6</u>	<u>\$ 349.8</u>
Less:					
Cash paid for interest ⁽¹⁾	171.7	146.3	124.4	42.8	46.1
Maintenance capital expenditures ⁽²⁾	94.6	63.0	58.9	50.5	47.1
Other ⁽³⁾	0.6	0.4	0.4	(1.0)	3.0
Add:					
Cash received for settlements ⁽⁴⁾	9.6	-	-	-	-
Asset impairment	30.5	5.8	-	3.0	19.2
Distributable Cash Flow	<u>\$ 390.9</u>	<u>\$ 454.3</u>	<u>\$ 314.3</u>	<u>\$ 385.3</u>	<u>\$ 272.8</u>

- (1) The year ended December 31, 2011, includes \$21.0 million of premiums paid for the early extinguishment of debt.
- (2) The year ended December 31, 2011, includes \$14.3 million of maintenance capital expenditures related to repairs associated with a fire at our Carthage compressor station.
- (3) Includes non-cash items such as the equity component of allowance for funds used during construction.
- (4) Represents proceeds received related to insurance recoveries associated with the Carthage compressor station incident and a legal settlement.

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

Overview

We own and operate three interstate natural gas pipeline systems, including integrated storage facilities. Our pipeline systems originate in the Gulf Coast region, Oklahoma and Arkansas, and extend northeasterly to the Midwestern states of Tennessee, Kentucky, Illinois, Indiana and Ohio.

Our pipeline systems contain approximately 14,200 miles of interconnected pipelines, directly serving customers in twelve states and indirectly serving customers throughout the northeastern and southeastern U.S. through numerous interconnections with unaffiliated pipelines. In 2011, our pipeline systems transported approximately 2.7 Tcf of gas. Average daily throughput on our pipeline systems during 2011 was approximately 7.3 Bcf. Our natural gas storage facilities are comprised of eleven underground storage fields located in four states with aggregate working gas capacity of approximately 167.0 Bcf. We conduct all of our natural gas transportation and integrated storage operations through our operating subsidiaries as one segment.

Our transportation services consist of firm transportation, whereby the customer pays a capacity reservation charge to reserve pipeline capacity at certain receipt and delivery points along our pipeline systems, plus a commodity and fuel charge on the volume of natural gas actually transported, and interruptible transportation, whereby the customer pays to transport gas only when capacity is available and used. We offer firm storage services in which the customer reserves and pays for a specific amount of storage capacity, including injection and withdrawal rights, and interruptible storage and PAL services where the customer receives and pays for capacity only when it is available and used. Some PAL agreements are paid for at inception of the service and revenues for these agreements are recognized as service is provided over the term of the agreement. We are not in the business of buying and selling natural gas other than for system management purposes, but changes in the level of natural gas prices may impact the volumes of gas transported on our pipeline systems. Our operating costs and expenses typically do not vary significantly based upon the amount of gas transported, with the exception of fuel consumed at our compressor stations, which is included in *Fuel and gas transportation* expenses on our Consolidated Statements of Income.

Recent Developments

In December 2011, HP Storage, a joint venture between us and BPHC of which we own a 20% interest, acquired Petal and Hattiesburg and related entities for \$550.0 million. Petal and Hattiesburg own seven high deliverability salt dome natural gas storage caverns and related assets in Forrest County, Mississippi. The storage caverns have approximately 29.0 Bcf of total storage capacity, of which approximately 18.6 Bcf is working gas capacity. The other assets include a leaching plant, freshwater and brine disposal wells, approximately 69,000 horsepower of compression and approximately 105 miles of pipeline which connect the storage facilities with several major natural gas pipelines, including our Gulf South pipeline. We operate the assets of HP Storage on behalf of the joint venture. HP Storage is in the process of leaching a new salt dome storage cavern which will add approximately 5.0 Bcf of working gas capacity and is expected to be placed in service in the first quarter 2013.

In late 2011 and early 2012, we transferred 340 miles of pipeline and two compressor stations to Boardwalk Field Services. These facilities were modified so that condensate-rich Eagle Ford Shale gas can be accepted into the pipeline. In February 2012, Field Services entered into a definitive agreement to construct a cryogenic gas processing plant and approximately 55 miles of gathering pipeline to serve producers in the Eagle Ford Shale producing area. This project is supported by long-term, fee-based gathering and processing agreements with Statoil Natural Gas LLC and Talisman Energy USA, Inc.

In October 2011, Field Services and Southwestern Energy Production Company executed a fifteen-year definitive gas gathering agreement which will require construction of high-pressure gas pipeline, a low-pressure gathering pipeline, compression and dehydration assets in Susquehanna and Lackawanna Counties, Pennsylvania.

Refer to Item 1 for further discussion of these projects.

Market Conditions and Contract Renewals

The majority of our revenues are derived from capacity reservation charges under firm agreements that are not impacted by the volume of natural gas transported or stored, and a smaller portion of our revenues are derived from charges based on actual volumes transported under firm and interruptible services. For example, for the twelve months ended December 31, 2011, approximately 82% of our revenues were derived from capacity reservation charges and 18% of our revenues were derived from charges based on actual volumes transported or stored.

As of December 31, 2011, a substantial portion of our transportation capacity has been contracted for under firm agreements having a weighted-average remaining life of approximately 6.0 years. However, an important aspect of our business is our ability to market available short-term firm or interruptible transportation capacity and renew existing longer-term transportation contracts. We actively market our available capacity which includes reserved capacity not fully utilized. The revenues we will be able to earn from that available capacity and from renewals of expiring contracts will be influenced by basis spreads and other factors discussed below.

Our ability to market available transportation capacity is impacted by supply and demand for natural gas, competition from other pipelines, natural gas price volatility, the price differential between physical locations on our pipeline systems (basis spreads), economic conditions and other factors. Over the past several years, new sources of natural gas have been identified throughout the U.S. and new pipeline infrastructure has been developed, which has led to changes in pricing dynamics between supply basins, pooling points and market areas and an overall weakening of basis spreads across our pipeline systems.

The narrowing of basis spreads on our pipeline systems has made it more difficult to renew expiring long-term firm transportation contracts at previously contracted rates because, as basis spreads decrease, the rates customers are willing to pay decrease. In addition, as rates decline customers typically seek longer-term agreements while we generally seek shorter terms. Changing basis spreads do not have as significant or immediate of an impact on long-term firm agreements as they do on short-term or interruptible services because long-term agreements are also influenced by other factors, such as baseload supply needs, certainty of delivery, predictability of long-term costs, the ability to manage those costs through the capacity release mechanism and the terms of service. The changes in the pricing dynamics and weakening of basis spreads have contributed to decreases in our operating profitability especially with regard to short-term and interruptible services. However, in 2011, revenues from power customers increased and we continue to see additional interest from this customer group.

Our ability to market available storage capacity and PAL is impacted by many of the factors indicated above, as well as natural gas price differentials between time periods, such as winter to summer (time period price spreads). These time period price spreads have declined over the 2010 to 2011 periods and have resulted in a significant reduction in our PAL and interruptible storage revenues in 2011 as compared to 2010.

Pipeline System Maintenance

We incur substantial costs for ongoing maintenance of our pipeline systems and related facilities, some of which reflect increased regulatory requirements applicable to all interstate pipelines. These costs include those incurred for pipeline integrity management activities, equipment overhauls, general upkeep and repairs. PHMSA has developed regulations that require transportation pipeline operators to implement integrity management programs to comprehensively evaluate certain areas along pipelines and take additional measures to protect pipeline segments located in highly populated areas. A recently enacted pipeline safety bill could result in increased regulatory requirements.

In 2012, we expect to incur costs of approximately \$260.0 million to maintain our pipeline systems, of which approximately \$91.3 million is expected to be recorded as maintenance capital. In 2011, these costs were approximately \$250.0 million, of which approximately \$80.3 million was recorded as maintenance capital, excluding the capital costs incurred for repairs associated with a fire at our Carthage compressor station. The projected increase of \$10.0 million is primarily related to pipeline integrity projects and general pipeline maintenance and repairs which are necessary to comply with regulatory requirements.

Results of Operations

2011 Compared with 2010

Our net income for the year ended December 31, 2011, decreased \$69.4 million, or 24%, to \$220.0 million compared to \$289.4 million for the year ended December 31, 2010. The decrease in net income was a result of a charge related to our materials and supplies, decreased PAL and storage revenues, increased operations and maintenance expenses and a loss on the early extinguishment of debt. These unfavorable impacts to net income were partially offset by higher gas transportation revenues from increased capacities.

Operating revenues for the year ended December 31, 2011, increased \$22.0 million, or 2%, to \$1,138.8 million, compared to \$1,116.8 million for the year ended December 31, 2010. Gas transportation revenues, excluding fuel, increased \$59.6 million primarily from increased capacities resulting from the completion of several compression projects in 2010 and operating our Fayetteville Lateral at its design capacity. PAL and storage revenues decreased \$21.6 million due to decreased parking opportunities from unfavorable natural gas price spreads between time periods and fuel retained decreased \$16.0 million primarily due to lower natural gas prices.

Operating costs and expenses for the year ended December 31, 2011, increased \$69.2 million, or 10%, to \$746.1 million, compared to \$676.9 million for the year ended December 31, 2010. In 2011, we recognized an impairment charge of \$28.8 million related to materials and supplies, most of which was subsequently sold. Operation and maintenance expenses increased by \$17.8 million primarily due to maintenance projects for pipeline integrity management and reliability spending and lower amounts of labor capitalized from fewer growth projects. Other drivers for the increased operating expenses were higher depreciation and property taxes of \$12.0 million associated with an increase in our asset base and reduced gains from the sale of storage gas needed to support operations of \$8.3 million. These increases were partially offset by lower fuel consumed of \$8.8 million primarily due to lower natural gas prices.

Total other deductions increased by \$22.3 million, or 15%, to \$172.3 million for the year ended December 31, 2011, compared to \$150.0 million for the 2010 period, driven by a \$13.2 million loss on the early extinguishment of debt and higher interest expense of \$8.3 million resulting from higher average interest rates on our long-term debt and lower capitalized interest.

2010 Compared with 2009

Our net income for the year ended December 31, 2010, increased \$126.7 million, or 78%, to \$289.4 million compared to \$162.7 million for the year ended December 31, 2009. The primary drivers were higher transportation revenues from our pipeline expansion projects and gains on gas sales associated with our Western Kentucky Storage Expansion project and a reduction in storage gas needed to support no-notice services, partially offset by increased operating expenses related to higher depreciation and property taxes associated with the pipeline expansion projects and increased interest expense. In 2009, gas transportation revenues and throughput were negatively impacted due to operating our pipeline expansion projects at reduced operating pressures and portions of the pipeline expansion projects being shut down for periods of time following the discovery and remediation of anomalies in certain joints of pipe.

Operating revenues for the year ended December 31, 2010, increased \$207.6 million, or 23%, to \$1,116.8 million, compared to \$909.2 million for the year ended December 31, 2009. Gas transportation revenues, excluding fuel, increased \$199.1 million and fuel retained increased \$31.2 million primarily due to our pipeline expansion projects. The increases were partially offset by \$13.7 million of lower interruptible and short-term firm transportation services resulting from lower basis spreads between delivery points on our pipeline systems. PAL and storage revenues decreased \$9.0 million due to decreased parking opportunities from unfavorable natural gas price spreads between time periods.

Operating costs and expenses for the year ended December 31, 2010, increased \$62.2 million, or 10%, to \$676.9 million, compared to \$614.7 million for the year ended December 31, 2009. The primary drivers of the increase were increased fuel consumed of \$46.9 million from our pipeline expansion projects and higher natural gas prices. Depreciation and property taxes increased by \$24.1 million associated with an increase in our asset base.

Operation and maintenance expenses increased \$9.9 million primarily due to an increase in major maintenance projects. Impairment losses of \$5.8 million were recognized in 2010 primarily related to the sale of assets in the Overton Field area in northeast Texas and a portion of pipe materials which we expect to dispose of by sale. The increased expenses were partly offset by a \$17.9 million gain from the sale of gas related to our Western Kentucky Storage Expansion project and a reduction in storage gas needed to support no-notice services. The 2009 period was unfavorably impacted by \$7.5 million as a result of pipeline investigation and retirement costs related to the East Texas Pipeline.

Total other deductions increased by \$18.5 million, or 14%, to \$150.0 million for the year ended December 31, 2010, compared to \$131.5 million for the 2009 period, driven by higher interest expense of \$18.9 million resulting from increased debt levels in 2010 and lower capitalized interest due to the completion of our pipeline expansion projects.

Liquidity and Capital Resources

We are a partnership holding company and derive all of our operating cash flow from our operating subsidiaries. Our principal sources of liquidity include cash generated from operating activities, our revolving credit facility, debt issuances and sales of limited partner units. Our operating subsidiaries use cash from their respective operations to fund their operating activities and maintenance capital requirements, service their indebtedness and make advances or distributions to Boardwalk Pipelines. Boardwalk Pipelines uses cash provided from the operating subsidiaries and, as needed, borrowings under our revolving credit facility to service outstanding indebtedness and make distributions or advances to us to fund our distributions to unitholders. We have no material guarantees of debt or other similar commitments to unaffiliated parties.

Capital Expenditures

Maintenance capital expenditures for the years ended December 31, 2011, 2010 and 2009 were \$94.6 million, \$63.0 million and \$58.9 million. Growth capital expenditures, including costs associated with our recently completed pipeline expansion projects, were \$46.6 million, \$160.7 million and \$754.2 million for the years ended December 31, 2011, 2010 and 2009. We expect our 2012 maintenance capital expenditures to be approximately \$91.3 million, \$43.0 million of which is for system maintenance primarily related to pipeline integrity management.

Our more significant growth projects for 2012 are discussed above in *Recent Developments* and consist of:

South Texas Eagle Ford Expansion: We expect to spend approximately \$180.0 million to construct a gathering pipeline and a cryogenic processing plant in south Texas, of which we expect to spend approximately \$173.0 million in 2012.

Marcellus Gathering System: We expect to spend approximately \$90.0 million to construct a gathering pipeline in Pennsylvania, of which we expect to spend approximately \$70.0 million in 2012.

HP Storage: HP Storage expects to spend approximately \$35.0 million to lease a new salt dome storage cavern which will add working gas capacity of approximately 5.0 Bcf, all of which is expected to be spent in 2012. We currently own a 20% equity interest in HP Storage. If it makes economic sense for us and BPHC, we could seek to acquire the remaining 80% equity interest in HP Storage that we do not currently own. Neither we nor BPHC is under any obligation with respect to such a transaction.

Refer to Item 1 for further discussion of these projects.

Equity and Debt Financing

We may seek to access the capital markets to fund some or all of the growth capital expenditures described above. In addition, we have the following indebtedness maturing over the next 12 months which we expect to refinance through capital market transactions or bank loans: (i) our revolving credit facility matures in June 2012, however all revolving loans outstanding at maturity may, at our election, be converted to term loans which mature in June 2013; (ii) \$225.0 million of 5.75% senior unsecured Gulf South notes mature in August 2012; and (iii) our

\$100.0 million subordinated loan from BPHC matures in December 2012, but is extendable by us for up to a year if we extend the term on our revolving credit facility. Our ability to access the capital markets for debt and equity financing under reasonable terms depends on our financial condition, credit ratings and market conditions.

We anticipate that our existing capital resources, including our revolving credit facility, and future cash flows will be adequate to fund our operations, including our maintenance capital expenditures. We expect to issue and sell debt and/or equity securities and to incur other indebtedness for the purposes described above and may also do so for general corporate purposes, or to fund potential acquisitions and new growth opportunities.

In February 2012, we completed a public offering of 9.2 million of our common units at a price of \$27.55 per unit. We received net cash proceeds of approximately \$250.2 million after deducting underwriting discounts and offering expenses of \$8.5 million and including a \$5.2 million contribution received from our general partner to maintain its 2% general partner interest. The net proceeds were used to repay borrowings under our revolving credit facility, which increased our available borrowing capacity under the facility.

In January 2011, we received net proceeds of approximately \$322.0 million after deducting initial purchaser discounts and offering expenses of \$3.0 million from the sale of \$325.0 million of 4.50% senior unsecured notes of Texas Gas due February 1, 2021 (2021 Notes). In June 2011, we issued an additional \$115.0 million of the 2021 Notes. The additional issuance was priced at a premium resulting in net proceeds of \$115.6 million after deducting underwriter discounts and offering expenses of \$1.0 million. We used the proceeds from both offerings to repay borrowings under our revolving credit facility and redeem Texas Gas' 5.50% notes due April 1, 2013 (2013 Notes) for which we paid premiums of \$21.0 million. Note 7 in Item 8 of this report contains more information about the 2021 Notes and redemption of the 2013 Notes.

In June 2011, we completed a public offering of 6.0 million of our common units at a price of \$29.33 per unit. We received net cash proceeds of approximately \$173.6 million after deducting underwriting discounts and offering expenses of \$6.0 million and including a \$3.6 million contribution received from our general partner to maintain its 2% general partner interest. The net proceeds were used to repay borrowings under our revolving credit facility.

Revolving Credit Facility

We maintain a revolving credit facility which has aggregate lending commitments of \$950.0 million, under which Boardwalk Pipelines, Gulf South and Texas Gas each may borrow funds, up to applicable sub-limits. Interest on amounts drawn under the credit facility is payable at a floating rate equal to an applicable spread per annum over the London Interbank Offered Rate or a base rate defined as the greater of the prime rate or the Federal funds rate plus 50 basis points. The revolving credit facility has a maturity date of June 29, 2012, however all outstanding revolving loans on such date may be converted to term loans having a maturity date of June 29, 2013. As of December 31, 2011, we had \$458.5 million of loans outstanding under our revolving credit facility with a weighted-average interest rate of 0.52% and no letters of credit issued thereunder. Subsequent to December 31, 2011, we repaid \$115.0 million of borrowings, which decreased borrowings to \$343.5 million, resulting in available borrowing capacity of \$606.5 million.

Our revolving credit facility contains customary negative covenants, including, among others, limitations on the payment of cash dividends and other restricted payments, the incurrence of additional debt, sale-leaseback transactions and transactions with our affiliates. The facility also contains a financial covenant that requires us and our subsidiaries to maintain a ratio of total consolidated debt to consolidated EBITDA (as defined in the credit agreement), measured for the preceding twelve months, of not more than five to one. We and our subsidiaries were in compliance with all covenant requirements under our credit facility at December 31, 2011. Although we do not believe that these covenants have had, or will have, a material impact on our business and financing activities or our ability to obtain the financing to maintain operations and continue our capital investments, they could restrict us in some circumstances as stated in Item 1A, *Risk Factors*. Note 7 in Item 8 of this Report contains more information regarding our revolving credit facility.

Contractual Obligations

The following table summarizes significant contractual cash payment obligations under firm commitments as of December 31, 2011, by period (in millions):

	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Principal payments on long-term debt ⁽¹⁾	\$ 3,208.5	\$ 783.5	\$ -	\$ 775.0	\$ 1,650.0
Interest on long-term debt ⁽²⁾	906.2	151.7	261.4	223.6	269.5
Capital commitments ⁽³⁾	16.7	16.7	-	-	-
Pipeline capacity agreements ⁽⁴⁾	48.5	9.0	17.0	14.4	8.1
Operating lease commitments	19.2	4.4	7.5	6.3	1.0
Total	\$ 4,199.1	\$ 965.3	\$ 285.9	\$ 1,019.3	\$ 1,928.6

(1) Includes our senior unsecured notes, having maturity dates from 2012 to 2027, \$458.5 million of loans outstanding under our revolving credit facility, having a maturity date of June 29, 2012, and our Subordinated Loans which mature initially on December 29, 2012. Amounts outstanding under the revolving credit facility are extendable by us for an additional year and the maturity date of the Subordinated Loans may be extended by a year if we elect to extend the term of the revolving credit facility. We have reflected the \$225.0 million of Gulf South notes due August 2012 (Gulf South 2012 Notes) as due in less than one year. The Gulf South 2012 Notes are included in long-term debt on our balance sheet, because we expect to refinance these notes on a long-term basis and we have sufficient available capacity under our revolving credit facility to extend the amount that would otherwise come due in less than one year.

(2) Interest obligations represent interest due on our senior unsecured notes at fixed rates. Future interest obligations under our revolving credit facility are uncertain, due to the variable interest rate and fluctuating balances. Based on a 0.52% weighted-average interest rate on amounts outstanding

under our revolving credit facility as of December 31, 2011, \$1.2 million would be due under the credit facility in less than one year.

- (3) Capital commitments represent binding commitments under purchase orders for materials ordered but not received and firm commitments under binding construction service agreements existing at December 31, 2011.
- (4) The amounts shown are associated with various pipeline capacity agreements on third-party pipelines that allow our operating subsidiaries to transport gas to off-system markets on behalf of our customers.

Pursuant to the settlement of the Texas Gas rate case in 2006, we are required to annually fund an amount to the Texas Gas pension plan equal to the amount of actuarially determined net periodic pension cost, including a minimum of \$3.0 million. In 2012, we expect to fund approximately \$9.0 million to the Texas Gas pension plan.

Distributions

For the twelve months ended December 31, 2011, 2010 and 2009, we paid distributions of \$419.9 million, \$398.1 million and \$360.6 million to our partners. Note 10 in Item 8 of this report contains further discussion regarding our distributions.

Changes in cash flow from operating activities

Net cash provided by operating activities decreased \$11.3 million to \$453.4 million for the year ended December 31, 2011, compared to \$464.7 million for the comparable 2010 period, primarily due to a decrease in net income, excluding the non-cash materials and supplies impairment charge.

Changes in cash flow from investing activities

Net cash used in investing activities decreased \$24.6 million to \$171.8 million for the year ended December 31, 2011, compared to \$196.4 million for the comparable 2010 period. The decrease was driven by an \$85.6 million decrease in capital expenditures primarily related to compression projects which were completed in 2010. The decrease was partly offset by uses of cash which included \$71.2 million of contributions related to our interest in HP Storage.

Changes in cash flow from financing activities

Net cash used in financing activities increased \$65.6 million to \$324.7 million for the year ended December 31, 2011, compared to \$259.1 million for the comparable 2010 period. The increase in cash used in financing activities resulted from net repayments of \$207.4 million of long-term debt, including net repayments under our revolving credit facility, a \$21.0 million premium paid on the early extinguishment of long-term debt and a \$21.8 million increase in distributions to our partners. The increase in the use of cash was partly offset by a \$173.6 million increase in proceeds from the issuance and sale of equity, including related general partner contributions, and \$10.7 million of payments made under our registration rights agreement in 2010.

Impact of Inflation

The cumulative impact of inflation over a number of years has resulted in increased costs for current replacement of productive facilities. The majority of our property, plant and equipment and materials and supplies is subject to rate-making treatment, and under current FERC practices, recovery is limited to historical costs. Amounts in excess of historical cost are not recoverable unless a rate case is filed. However, cost-based regulation, along with competition and other market factors, may limit our ability to price jurisdictional services to ensure recovery of inflation's effect on costs.

Off-Balance Sheet Arrangements

At December 31, 2011, we had no guarantees of off-balance sheet debt to third parties, no debt obligations that contain provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings, and no other off-balance sheet arrangements.

Critical Accounting Policies

Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time the financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities and our disclosure of contingent assets and liabilities in our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with third parties and other methods we consider reasonable. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the periods in which the facts that give rise to the revisions become known.

Regulation

Our subsidiaries are regulated by FERC. Pursuant to FERC regulations certain revenues that we collect may be subject to possible refunds to our customers. Accordingly, during an open rate case, estimates of rate refund reserves are recorded based on regulatory proceedings, advice of counsel and estimated risk-adjusted total exposure, as well as other factors. At December 31, 2011 and 2010, there were no liabilities for any open rate case recorded on our Consolidated Balance Sheets. Currently, neither Gulf South nor Texas Gas is involved in an open general rate case; however Gulf Crossing filed a cost and revenue study to justify its initial firm transportation rates in January 2012. The outcome of this filing is not expected to have a material impact on our business, financial condition, results of operations or cash flows.

When certain criteria are met, GAAP requires that certain rate-regulated entities account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates (regulatory accounting). This basis of accounting is applicable to operations of our Texas Gas subsidiary which records certain costs and benefits as regulatory assets and liabilities in order to provide for recovery from or refund to customers in future periods, but is not applicable to operations associated with the Fayetteville and Greenville Laterals due to rates charged under negotiated rate agreements and a portion of the storage capacity due to the regulatory treatment associated with the rates charged for that capacity. Regulatory accounting is not applicable to Gulf Crossing due to discounts under negotiated rate agreements, or Gulf South because competition in the market areas of Gulf South has resulted in discounts from the maximum allowable cost-based rates being granted to customers and certain services provided by Gulf South are priced using market-based rates.

We monitor the regulatory and competitive environment in which we operate to determine that any regulatory assets continue to be probable of recovery. If we were to determine that all or a portion of our regulatory assets no longer met the criteria for recognition as regulatory assets, that portion which was not recoverable would be written off, net of any regulatory liabilities. Note 6 in Item 8 of this Report contains more information regarding our regulatory assets and liabilities.

In the course of providing transportation and storage services to customers, the pipelines may receive different quantities of gas from shippers and operators than the quantities delivered by the pipelines on behalf of those shippers and operators. This results in transportation and exchange gas receivables and payables, commonly known as imbalances, which are primarily settled in cash or the receipt or delivery of gas in the future. Settlement of imbalances requires agreement between the pipelines and shippers or operators as to allocations of volumes to specific transportation contracts and timing of delivery of gas based on operational conditions. The receivables and payables are valued at market price for operations where regulatory accounting is not applicable and are valued at the historical value of gas in storage for operations where regulatory accounting is applicable, consistent with the regulatory treatment.

Fair Value Measurements

Fair value refers to an exit price that would be received to sell an asset or paid to transfer a liability in an orderly transaction in the principal market in which the reporting entity transacts based on the assumptions market participants would use when pricing the asset or liability assuming its highest and best use. A fair value hierarchy has been established that prioritizes the information used to develop those assumptions giving priority, from highest to lowest, to quoted prices in active markets for identical assets and liabilities (Level 1); observable inputs not included in Level 1, for example, quoted prices for similar assets and liabilities (Level 2); and unobservable data (Level 3), for example, a reporting entity's own internal data based on the best information available in the circumstances.

Our financial statements and certain disclosures include fair value measurements. Notes 4, 5, 8, 9 and 12 contain more information regarding our fair value measurements.

Environmental Liabilities

Our environmental liabilities are based on management's best estimate of the undiscounted future obligation for probable costs associated with environmental assessment and remediation of our operating sites. These estimates are based on evaluations and discussions with counsel and operating personnel and the current facts and circumstances related to these environmental matters. At December 31, 2011, we had accrued approximately \$8.8 million for environmental matters. Our environmental accrued liabilities could change substantially in the future due to factors such as the nature and extent of any contamination, changes in remedial requirements, technological changes, discovery of new information, and the involvement of and direction taken by the EPA, FERC and other governmental authorities on these matters. We continue to conduct environmental assessments and are implementing a variety of remedial measures that may result in increases or decreases in the total estimated environmental costs. Note 3 in Item 8 of this Report contains more information regarding our environmental liabilities.

Impairment of Long-Lived Assets

We periodically evaluate whether the carrying amount of long-lived assets has been impaired when circumstances indicate the carrying amount of those assets may not be recoverable. This evaluation is based on undiscounted cash flow projections expected to be realized over the remaining useful life of the asset. The carrying amount is not recoverable if it exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. If the carrying amount is not recoverable, the impairment loss is measured as the excess of the asset's carrying amount over its fair value. Note 4 in Item 8 of this Report contains more information regarding impairments we have recognized.

Goodwill

In September 2011, the Financial Accounting Standards Board issued Accounting Standards Update 2011-08 (ASU 2011-08), which amended the rules for testing goodwill for impairment. Under the new rules, an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. In accordance with new GAAP requirements, beginning in 2011, we have elected to perform a qualitative assessment on an annual basis to determine whether events or circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If indications are that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, a quantitative analysis is performed to measure whether the fair value of the reporting unit is less than its carrying amount. If the fair value is less than the carrying amount an additional step is taken to measure the amount of goodwill impairment, if any.

As of December 31, 2011, we assessed qualitative factors to determine whether it was more likely than not that the fair value of the reporting unit associated with our goodwill was less than its carrying amount. We concluded that more likely than not the fair value of the reporting unit associated with our goodwill was not less than its carrying amount. Accordingly, the quantitative goodwill impairment analysis was not performed and no

impairment of goodwill was recorded during 2011. No impairment of goodwill was recorded during 2010 or 2009. Our qualitative included an analysis of factors requiring estimates and judgments. The use of alternate judgments and/or assumptions could substantially change the results of the assessment, requiring a quantitative test to be performed and potentially result in the recognition of an impairment charge in our financial statements.

Defined Benefit Plans

We are required to make a significant number of assumptions in order to estimate the liabilities and costs related to our pension and postretirement benefit obligations to employees under our benefit plans. The assumptions that have the most impact on pension and postretirement benefit costs are the discount rate, the expected return on plan assets and the rate of compensation increases. These assumptions are evaluated relative to current market factors in the U.S. such as inflation, interest rates and fiscal and monetary policies, as well as our policies regarding management of the plans such as the allocation of plan assets among investment options. Changes in these assumptions can have a material impact on obligations and related expense associated with these plans.

In determining the discount rate assumption, we utilize current market information and liability information provided by our plan actuaries, including a discounted cash flow analysis of our pension and postretirement obligations. In particular, the basis for our discount rate selection was the yield on indices of highly rated fixed income debt securities with durations comparable to that of our plan liabilities. The Moody's Aa Corporate Bond Index is consistently used as the basis for the change in discount rate from the last measurement date with this measure confirmed by the yield on other broad bond indices. Additionally, we supplement our discount rate decision with a yield curve analysis. The yield curve is applied to expected future retirement plan payments to adjust the discount rate to reflect the cash flow characteristics of the plans. The yield curve is developed by the plans' actuaries and is a hypothetical AA/Aa yield curve represented by a series of annualized discount rates reflecting bond issues having a rating of Aa or better by Moody's Investors Service, Inc. or a rating of AA or better by Standard & Poor's. Note 9 in Item 8 of this Report contains more information regarding our pension and postretirement benefit obligations.

Forward-Looking Statements

Investors are cautioned that certain statements contained in this Report, as well as some statements in periodic press releases and some oral statements made by our officials and our subsidiaries during presentations about us, are "forward-looking." Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements, and may contain the words "expect," "intend," "plan," "anticipate," "estimate," "believe," "will likely result," and similar expressions. In addition, any statement made by our management concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions by our partnership or our subsidiaries, are also forward-looking statements.

Forward-looking statements are based on current expectations and projections about future events and their potential impact on us. While management believes that these forward-looking statements are reasonable as and when made, there is no assurance that future events affecting us will be those that we anticipate. All forward-looking statements are inherently subject to a variety of risks and uncertainties, many of which are beyond our control that could cause actual results to differ materially from those anticipated or projected. These risks and uncertainties include, among others:

- the impact of new pipelines or new gas supply sources on competition and basis spreads on our pipeline systems;
- our ability to maintain or replace expiring gas transportation and storage contracts and to sell short-term capacity on our pipelines;
- the impact of changes to laws and regulations, such as the proposed greenhouse gas legislation and the re-authorization by Congress of the Pipeline and Hazardous Materials Safety Administration, the recently enacted pipeline safety bill, and regulatory changes that result from that legislation applicable to interstate pipelines, on our business, including our costs, liabilities and revenues;

- the costs of maintaining and ensuring the integrity and reliability of our pipeline systems;
- the timing, cost, scope and financial performance of our recent, current and future growth projects;
- the expansion into new product lines and geographic areas;
- volatility or disruptions in the capital or financial markets;
- the impact of FERC's rate-making policies and actions on the services we offer and the rates we charge and our ability to recover the full cost of operating our pipelines, including earning a reasonable return;
- operational hazards, litigation and unforeseen interruptions for which we may not have adequate or appropriate insurance coverage;
- the future cost of insuring our assets;
- our ability to access new sources of natural gas and the impact on us of any future decreases in supplies of natural gas in our supply areas;
- the consummation of contemplated transactions and agreements; and
- the impact on our system throughput and revenues from changes in the supply of and demand for natural gas, including as a result of commodity price changes.

Developments in any of these areas could cause our results to differ materially from results that have been or may be anticipated or projected. Forward-looking statements speak only as of the date of this Report and we expressly disclaim any obligation or undertaking to update these statements to reflect any change in our expectations or beliefs or any change in events, conditions or circumstances on which any forward-looking statement is based.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest rate risk:

With the exception of our revolving credit facility, for which the interest rate is periodically reset, our debt has been issued at fixed rates. For fixed rate debt, changes in interest rates affect the fair value of the debt instruments but do not directly affect earnings or cash flows. The following table presents market risk associated with our fixed-rate long-term debt, including our Subordinated Loans, at December 31 (in millions, except interest rates):

	<u>2011</u>	<u>2010</u>
Carrying value of fixed-rate debt	\$ 2,740.2	\$ 2,548.8
Fair value of fixed-rate debt	\$ 2,985.1	\$ 2,717.0
100 basis point increase in interest rates and resulting debt decrease	\$ 135.6	\$ 126.0
100 basis point decrease in interest rates and resulting debt increase	\$ 148.8	\$ 126.5
Weighted-average interest rate, including Subordinated Loan	5.78%	5.97%

At December 31, 2011, we had \$458.5 million outstanding under our revolving credit facility at a weighted-average interest rate of 0.52% which rate is reset periodically. A 1% increase in interest rates would increase our cash payments for interest on the credit facility by \$4.6 million on an annualized basis. At December 31, 2010, we had \$703.5 million outstanding under our revolving credit facility at a weighted-average interest rate of 0.53%.

A significant portion of our debt, including our revolving credit facility, will mature over the next five years. We expect to refinance the debt either prior to or at maturity. Our ability to refinance the debt at interest rates that are currently available is subject to risk at the magnitude illustrated in the table. We expect to refinance the remainder of our debt that will mature based on our assessment of the term rates of interest available in the market.

At December 31, 2011 and 2010, \$11.9 million and \$55.0 million of our undistributed cash, shown on the balance sheets as *Cash and cash equivalents*, was primarily invested in Treasury fund accounts. Due to the short-term nature of the Treasury fund accounts, a hypothetical 10% increase or decrease in interest rates would not have a material effect on the fair market value of our *Cash and cash equivalents*.

Commodity risk:

Our pipelines do not take title to the natural gas which they transport and store in rendering firm and interruptible transportation and storage services, therefore they do not assume the related natural gas commodity price risk associated with that gas. However, certain volumes of our gas stored underground are available for sale and subject to commodity price risk. At December 31, 2011 and 2010, approximately \$1.7 million and \$3.6 million of gas stored underground, which we own and carry as current *Gas stored underground*, was available for sale and exposed to commodity price risk. Additionally, at December 31, 2010, we had 4.5 Bcf of gas with a book value of \$10.3 million that had become available for sale as a result of a change in the storage working gas needed to support operations and no-notice services at our Texas Gas subsidiary. We often utilize derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas, however, at December 31, 2011, we had no outstanding derivatives. Subsequent to December 31, 2011, we hedged approximately 1.9 Bcf of anticipated future sales of natural gas and cash for fuel reimbursement. The derivatives qualify for cash flow hedge accounting and are designated as such.

Market risk:

Our primary exposure to market risk occurs at the time our existing transportation and storage contracts expire and are subject to renewal or marketing. We actively monitor future expiration dates associated with our contract portfolio. The revenue we will be able to earn from renewals of expiring contracts will be influenced by basis spreads and other factors discussed below.

We compete with numerous interstate and intrastate pipelines. Our ability to market available transportation capacity is impacted by supply and demand for natural gas, competition from other pipelines, natural gas price volatility, the price differential between physical locations on our pipeline systems (basis spreads), economic conditions and other factors. Over the past several years, new sources of natural gas have been identified throughout the U.S. and new pipeline infrastructure has been developed which has led to changes in pricing dynamics between supply basins, pooling points and market areas and an overall weakening of basis spreads across our pipeline systems.

The narrowing of basis spreads on our pipeline systems has made it more difficult to renew expiring long-term firm transportation contracts at previously contracted rates because, as basis spreads decrease, the rates customers are willing to pay decrease. In addition, as rates decline customers typically seek longer-term agreements while we generally seek shorter terms. Changing basis spreads do not have as significant or immediate impacts on long-term firm agreements as they do on short-term or interruptible services because long-term agreements are also influenced by other factors, such as baseload supply needs, certainty of delivery, predictability of long-term costs, the ability to manage those costs through the capacity release mechanism and the terms of service. The changes in the pricing dynamics and weakening of basis spreads have contributed to decreases in our operating profitability, especially with regard to short-term and interruptible services. However, in 2011, revenues from power customers increased and we continue to see additional interest from this customer group, especially as power producers increase their reliance on natural gas.

Credit risk:

Our credit exposure generally relates to receivables for services provided, as well as volumes owed by customers for imbalances or gas lent by us to them, generally under PAL and no-notice services. Natural gas price volatility can materially increase credit risk related to gas loaned to customers. If any significant customer of ours should have credit or financial problems resulting in a delay or failure to repay the gas they owe to us, this could have a material adverse effect on our business, financial condition, results of operations or cash flows.

As of December 31, 2011, the amount of gas loaned out by our subsidiaries or owed to our subsidiaries due to gas imbalances was approximately 8.3 trillion British thermal units (TBtu). Assuming an average market price during December 2011 of \$3.14 per million British thermal units (MMBtu), the market value of that gas was approximately \$26.1 million. As of December 31, 2010, the amount of gas loaned out by our subsidiaries or owed to our subsidiaries due to gas imbalances was approximately 13.0 TBtu. Assuming an average market price during December 2010 of \$4.21 per MMBtu, the market value of this gas at December 31, 2010, would have been approximately \$54.7 million.

Although nearly all of our customers pay for our services on a timely basis, we actively monitor the credit exposure to our customers. We include in our ongoing assessments amounts due pursuant to services we render plus the value of any gas we have lent to a customer through no-notice or PAL services and the value of gas due to us under a transportation imbalance. Our pipeline tariffs contain language that allow us to require a customer that does not meet certain credit criteria to provide cash collateral, post a letter of credit or provide a guarantee from a credit-worthy entity in an amount equaling up to three months of capacity reservation charges. For certain agreements, we have included contractual provisions that require additional credit support should the credit ratings of those customers fall below investment grade.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Boardwalk GP, LLC
and the Partners of Boardwalk Pipeline Partners, LP

We have audited the accompanying consolidated balance sheets of Boardwalk Pipeline Partners, LP and subsidiaries (the “Partnership”) as of December 31, 2011 and 2010, and the related consolidated statements of income, changes in partners’ capital, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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 Boardwalk Pipeline Partners, LP and subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership’s internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2012, expressed an unqualified opinion on the Partnership’s internal control over financial reporting.

/s/ Deloitte & Touche LLP
Houston, Texas
February 21, 2012

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED BALANCE SHEETS

(Millions)

ASSETS	December 31,	
	2011	2010
Current Assets:		
Cash and cash equivalents	\$ 11.9	\$ 55.0
Receivables:		
Trade, net	98.0	101.0
Affiliate	0.3	-
Other	20.2	5.2
Gas transportation receivables	5.8	12.2
Costs recoverable from customers	9.8	11.3
Gas stored underground	1.7	3.6
Prepayments	13.3	11.4
Other current assets	1.8	3.5
Total current assets	<u>162.8</u>	<u>203.2</u>
Property, Plant and Equipment:		
Natural gas transmission and other plant	7,049.7	6,933.9
Construction work in progress	110.4	109.9
Property, plant and equipment, gross	<u>7,160.1</u>	<u>7,043.8</u>
Less—accumulated depreciation and amortization	997.1	785.8
Property, plant and equipment, net	<u>6,163.0</u>	<u>6,258.0</u>
Other Assets:		
Goodwill	163.5	163.5
Gas stored underground	107.5	125.8
Costs recoverable from customers	15.3	15.7
Investment in unconsolidated affiliate	70.1	-
Other	88.4	111.8
Total other assets	<u>444.8</u>	<u>416.8</u>
Total Assets	<u>\$ 6,770.6</u>	<u>\$ 6,878.0</u>

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED BALANCE SHEETS

(Millions)

LIABILITIES AND PARTNERS' CAPITAL	December 31,	
	2011	2010
Current Liabilities:		
Payables:		
Trade	\$ 42.8	\$ 48.8
Affiliates	3.2	3.2
Other	6.3	10.1
Gas Payables:		
Transportation	5.0	20.5
Storage	0.1	4.2
Accrued taxes, other	40.6	40.4
Accrued interest	45.2	40.5
Accrued payroll and employee benefits	18.4	17.0
Construction retainage	3.5	8.3
Deferred income	9.4	6.3
Other current liabilities	17.5	14.5
Total current liabilities	<u>192.0</u>	<u>213.8</u>
Long-term debt	3,098.7	3,152.3
Long-term debt – affiliate	100.0	100.0
Total long-term debt	<u>3,198.7</u>	<u>3,252.3</u>
Other Liabilities and Deferred Credits:		
Pension liability	27.3	27.0
Asset retirement obligation	16.7	17.2
Provision for other asset retirement	54.5	51.7
Payable to affiliate	16.0	16.0
Other	60.2	58.6
Total other liabilities and deferred credits	<u>174.7</u>	<u>170.5</u>
Commitments and Contingencies		
Partners' Capital:		
Common units – 175.7 million and 169.7 million units issued and outstanding as of December 31, 2011, and December 31, 2010	2,513.8	2,534.4
Class B units – 22.9 million units issued and outstanding as of December 31, 2011, and December 31, 2010	678.7	683.6
General partner	62.1	62.9
Accumulated other comprehensive loss	(49.4)	(39.5)
Total partners' capital	<u>3,205.2</u>	<u>3,241.4</u>
Total Liabilities and Partners' Capital	<u>\$ 6,770.6</u>	<u>\$ 6,878.0</u>

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF INCOME

(Millions, except per unit amounts)

	For the Year Ended December 31,		
	2011	2010	2009
Operating Revenues:			
Gas transportation	\$ 1,065.5	\$ 1,015.4	\$ 794.9
Parking and lending	12.0	28.1	34.9
Gas storage	49.9	55.4	57.6
Other	11.4	17.9	21.8
Total operating revenues	<u>1,138.8</u>	<u>1,116.8</u>	<u>909.2</u>
Operating Costs and Expenses:			
Fuel and gas transportation	102.7	109.4	61.9
Operation and maintenance	168.5	149.6	142.2
Administrative and general	132.7	126.6	122.0
Depreciation and amortization	225.2	217.9	203.1
Asset impairment	30.5	5.8	-
Net (gain) loss on disposal of operating assets	(2.4)	(16.6)	8.2
Taxes other than income taxes	88.9	84.2	77.3
Total operating costs and expenses	<u>746.1</u>	<u>676.9</u>	<u>614.7</u>
Operating income	<u>392.7</u>	439.9	294.5
Other Deductions (Income):			
Interest expense	151.3	142.9	125.3
Interest expense – affiliates	8.0	8.1	6.8
Loss on early retirement of debt	13.2	-	-
Interest income	(0.4)	(0.6)	(0.2)
Equity losses from unconsolidated affiliate	1.1	-	-
Miscellaneous other income, net	(0.9)	(0.4)	(0.4)
Total other deductions	<u>172.3</u>	<u>150.0</u>	<u>131.5</u>
Income before income taxes	220.4	289.9	163.0
Income taxes	0.4	0.5	0.3
Net Income	<u>\$ 220.0</u>	<u>\$ 289.4</u>	<u>\$ 162.7</u>
Net Income per Unit:			
Basic and diluted net income per unit:			
Common units	\$ 1.09	\$ 1.47	\$ 0.88
Class B units	\$ 0.14	\$ 0.62	\$ 0.08
Cash distribution declared and paid to common units	\$ 2.095	\$ 2.03	\$ 1.95
Cash distribution declared and paid to class B units	\$ 1.20	\$ 1.20	\$ 1.20
Weighted-average number of units outstanding:			
Common units	173.3	169.7	161.6
Class B units	22.9	22.9	22.9

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Millions)

	For the Year Ended December 31,		
	2011	2010	2009
Net income	\$ 220.0	\$ 289.4	\$ 162.7
Other comprehensive income (loss):			
Gain on cash flow hedges	3.1	6.0	10.5
Reclassification adjustment transferred to Net income from cash flow hedges	0.2	(13.0)	(16.5)
Pension and other postretirement benefit costs	(13.2)	(7.1)	(3.9)
Total Comprehensive Income	<u>\$ 210.1</u>	<u>\$ 275.3</u>	<u>\$ 152.8</u>

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)

	For the Year Ended December 31,		
	2011	2010	2009
OPERATING ACTIVITIES:			
Net income	\$ 220.0	\$ 289.4	\$ 162.7
Adjustments to reconcile to cash provided by operations:			
Depreciation and amortization	225.2	217.9	203.1
Amortization of deferred costs	9.3	8.1	9.4
Asset impairment	30.5	5.8	-
Loss on debt extinguishment	13.2	-	-
Storage gas loss	3.7	-	-
Net (gain) loss on disposal of operating assets	(2.4)	(16.6)	8.2
Equity losses in unconsolidated affiliate	1.1	-	-
Changes in operating assets and liabilities:			
Trade and other receivables	(12.9)	(9.7)	(23.4)
Other receivables, affiliates	(0.3)	-	-
Gas receivables and storage assets	16.3	(10.5)	(5.0)
Costs recoverable from customers	(2.6)	(5.4)	(1.6)
Other assets	(31.3)	23.1	(18.0)
Trade and other payables	(5.1)	(27.4)	25.9
Other payables, affiliates	-	0.7	0.7
Gas payables	(17.4)	10.0	2.4
Accrued liabilities	6.9	0.9	4.3
Other liabilities	(0.8)	(21.6)	31.8
Net cash provided by operating activities	<u>453.4</u>	<u>464.7</u>	<u>400.5</u>
INVESTING ACTIVITIES:			
Capital expenditures	(141.7)	(227.3)	(846.8)
Proceeds from sale of operating assets	31.5	30.9	-
Proceeds from insurance and other recoveries	9.6	-	-
Sales of short-term investments	-	-	175.0
Investment in unconsolidated affiliate	(71.2)	-	-
Net cash used in investing activities	<u>(171.8)</u>	<u>(196.4)</u>	<u>(671.8)</u>
FINANCING ACTIVITIES:			
Proceeds from long-term debt, net of issuance costs	437.6	-	346.7
Repayment of borrowings from long-term debt	(250.0)	-	-
Payments of premiums on extinguishment of long-term debt	(21.0)	-	-
Proceeds from borrowings on revolving credit agreement	585.0	175.0	411.5
Repayment of borrowings on revolving credit agreement	(830.0)	(25.0)	(650.0)
Payments on note payable	-	(0.3)	(1.3)
Proceeds from long-term debt – affiliate	-	-	200.0
Repayment of long-term debt – affiliate	-	-	(100.0)
Payments associated with registration rights agreement	-	(10.7)	-
Distributions paid	(419.9)	(398.1)	(360.6)
Proceeds from sale of common units	170.0	-	326.3
Capital contribution from general partner	3.6	-	6.8
Net cash (used in) provided by financing activities	<u>(324.7)</u>	<u>(259.1)</u>	<u>179.4</u>
(Decrease) increase in cash and cash equivalents	(43.1)	9.2	(91.9)
Cash and cash equivalents at beginning of period	55.0	45.8	137.7
Cash and cash equivalents at end of period	<u>\$ 11.9</u>	<u>\$ 55.0</u>	<u>\$ 45.8</u>

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP

**CONSOLIDATED STATEMENTS OF CHANGES IN
PARTNERS' CAPITAL**
(Millions)

	Common Units	Class B Units	General Partner	Accumulated Other Comp Income (Loss)	Total Partners' Capital
Balance January 1, 2009	\$ 2,504.8	\$ 692.8	\$ 62.9	\$ (15.5)	\$ 3,245.0
Add (deduct):					
Net income	128.2	18.2	16.3	-	162.7
Distributions paid	(312.7)	(27.4)	(20.5)	-	(360.6)
Sale of common units, net of related transaction costs	320.2	-	-	-	320.2
Capital contribution from general partner	-	-	6.8	-	6.8
Other comprehensive loss, net of tax	-	-	-	(9.9)	(9.9)
Balance December 31, 2009	\$ 2,640.5	\$ 683.6	\$ 65.5	\$ (25.4)	\$ 3,364.2
Add (deduct):					
Net income	238.4	27.4	23.6	-	289.4
Distributions paid	(344.5)	(27.4)	(26.2)	-	(398.1)
Other comprehensive loss, net of tax	-	-	-	(14.1)	(14.1)
Balance December 31, 2010	\$ 2,534.4	\$ 683.6	\$ 62.9	\$ (39.5)	\$ 3,241.4
Add (deduct):					
Net income	171.1	22.6	26.3	-	220.0
Distributions paid	(361.7)	(27.5)	(30.7)	-	(419.9)
Sale of common units, net of related transaction costs	170.0	-	-	-	170.0
Capital contribution from general partner	-	-	3.6	-	3.6
Other comprehensive loss, net of tax	-	-	-	(9.9)	(9.9)
Balance December 31, 2011	\$ 2,513.8	\$ 678.7	\$ 62.1	\$ (49.4)	\$ 3,205.2

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1: Corporate Structure

Boardwalk Pipeline Partners, LP (the Partnership) is a Delaware limited partnership formed in 2005 to own and operate the business conducted by its primary subsidiary Boardwalk Pipelines, LP (Boardwalk Pipelines), and its subsidiaries, Gulf Crossing Pipeline Company LLC (Gulf Crossing), Gulf South Pipeline Company, LP (Gulf South) and Texas Gas Transmission, LLC (Texas Gas) (together, the operating subsidiaries), which consist of integrated natural gas pipeline and storage systems. In 2011, the Partnership formed Boardwalk Midstream, LP (Midstream), and its operating subsidiary, Boardwalk Field Services, LLC (Field Services), which is engaged in the natural gas gathering and processing business. As of December 31, 2011, Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews), owned 102.7 million of the Partnership's common units, all 22.9 million of the Partnership's class B units and, through Boardwalk GP, LP (Boardwalk GP), an indirect wholly-owned subsidiary of BPHC, holds the 2% general partner interest and all of the incentive distribution rights (IDRs). As of February 21, 2012, the common units, class B units and general partner interest owned by BPHC represent approximately 61% of the Partnership's equity interests, excluding the IDRs. The Partnership's common units are traded under the symbol "BWP" on the New York Stock Exchange.

Basis of Presentation

The accompanying consolidated financial statements of the Partnership were prepared in accordance with accounting principles generally accepted in the United States of America (GAAP).

Note 2: Accounting Policies

Principles of Consolidation

The consolidated financial statements include the Partnership's accounts and those of its wholly-owned subsidiaries after elimination of intercompany transactions. The Partnership applies the equity method of accounting for investments in unconsolidated affiliates in which the Partnership owns 20 percent to 50 percent of the voting interests or otherwise exercises significant influence, but not control, over operating and financial policies of the investee. Under this method, the carrying amounts of the Partnership's equity investments are increased by a proportionate share of the investee's net income and contributions made, and decreased by a proportionate share of the investee's net losses and distributions received.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities and the fair values of certain items. The Partnership bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, which form the basis for making judgments about the carrying amounts of assets and liabilities that are not readily apparent from other sources. Actual results could differ from such estimates.

Segment Information

The Partnership operates in one reportable segment - the operation of interstate natural gas pipeline systems including integrated storage facilities. This segment consists of interstate natural gas pipeline systems which originate in the Gulf Coast region, Oklahoma and Arkansas, and extend north and east through the Midwestern states of Tennessee, Kentucky, Illinois, Indiana and Ohio.

Regulatory Accounting

The operating subsidiaries are regulated by the Federal Energy Regulatory Commission (FERC). When certain criteria are met, GAAP requires that certain rate-regulated entities account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates (regulatory accounting). This basis of accounting is applicable to operations of the Partnership's Texas Gas subsidiary which records certain costs and benefits as regulatory assets and liabilities in order to provide for recovery from or refund to customers in future periods, but is not applicable to operations associated with the Fayetteville and Greenville Laterals due to rates charged under negotiated rate agreements and a portion of the storage capacity due to the regulatory treatment associated with the rates charged for that capacity. Regulatory accounting is not applicable to the Partnership's Gulf Crossing subsidiary due to discounts under negotiated rate agreements, or Gulf South because competition in its market area has resulted in discounts from the maximum allowable cost-based rates being granted to customers and certain services provided by Gulf South are priced using market-based rates.

The Partnership monitors the regulatory and competitive environment in which it operates to determine that its regulatory assets continue to be probable of recovery. If the Partnership were to determine that all or a portion of its regulatory assets no longer met the criteria for recognition as regulatory assets, that portion which was not recoverable would be written off, net of any regulatory liabilities. Note 6 contains more information regarding the Partnership's regulatory assets and liabilities.

Cash and Cash Equivalents

Cash equivalents are highly liquid investments with an original maturity of three months or less and are stated at cost plus accrued interest, which approximates fair value. The Partnership had no restricted cash at December 31, 2011 and 2010.

Cash Management

The operating subsidiaries participate in an intercompany cash management program to the extent they are permitted under FERC regulations. Under the cash management program, depending on whether a participating subsidiary has short-term cash surpluses or cash requirements, Boardwalk Pipelines either provides cash to them or they provide cash to Boardwalk Pipelines. The transactions are represented by demand notes and are stated at historical carrying amounts. Interest income and expense is recognized on an accrual basis when collection is reasonably assured. The interest rate on intercompany demand notes is London Interbank Offered Rate (LIBOR) plus one percent and is adjusted every three months.

Trade and Other Receivables

Trade and other receivables are stated at their historical carrying amount, net of allowances for doubtful accounts. The Partnership establishes an allowance for doubtful accounts on a case-by-case basis when it believes the required payment of specific amounts owed is unlikely to occur. Uncollectible receivables are written off when a settlement is reached for an amount that is less than the outstanding historical balance or a receivable amount is deemed otherwise unrealizable.

Gas Stored Underground and Gas Receivables and Payables

The operating subsidiaries have underground gas in storage which is utilized for system management and operational balancing, as well as for services including firm and interruptible storage associated with certain no-notice and parking and lending (PAL) services. Gas stored underground includes the historical cost of natural gas volumes owned by the operating subsidiaries, at times reduced by certain operational encroachments upon that gas. Current gas stored underground represents net retained fuel remaining after providing transportation and storage services and excess working gas which is available for resale and is valued at the lower of weighted-average cost or market.

Gulf South and Texas Gas provide storage services whereby they store gas on behalf of customers and also periodically hold customer gas under PAL services. Since the customers retain title to the gas held by the Partnership in providing these services, the Partnership does not record the related gas on its balance sheet. The Partnership held for storage or under PAL agreements approximately 104.1 trillion British thermal units (TBTu) of gas owned by third parties as of December 31, 2011. Assuming an average market price during December 2011 of \$3.14 per million British thermal units (MMBTu), the market value of gas held on behalf of others was approximately \$326.9 million. As of December 31, 2010, the Partnership held for storage or under PAL agreements approximately 82.9 TBTu of gas owned by third parties. Gulf South and Texas Gas also periodically lend gas to customers under PAL services.

In the course of providing transportation and storage services to customers, the operating subsidiaries may receive different quantities of gas from shippers and operators than the quantities delivered on behalf of those shippers and operators. This results in transportation and exchange gas receivables and payables, commonly known as imbalances, which are settled in cash or the receipt or delivery of gas in the future. Settlement of imbalances requires agreement between the pipelines and shippers or operators as to allocations of volumes to specific transportation contracts and timing of delivery of gas based on operational conditions. The receivables and payables are valued at market price for operations where regulatory accounting is not applicable and are valued at the historical value of gas in storage for operations where regulatory accounting is applicable.

Materials and Supplies

Materials and supplies are carried at average cost and are included in *Other Assets* on the Consolidated Balance Sheets. The Partnership expects its materials and supplies to be used for capital projects related to its property, plant and equipment and for future growth projects.

Property, Plant and Equipment (PPE) and Repair and Maintenance Costs

PPE is recorded at its original cost of construction or fair value of assets purchased. Construction costs and expenditures for major renewals and improvements which extend the lives of the respective assets are capitalized. *Construction work in progress* is included in the financial statements as a component of PPE. All repair and maintenance costs are expensed as incurred.

Depreciation of PPE related to operations for which regulatory accounting does not apply is provided for using the straight-line method of depreciation over the estimated useful lives of the assets, which range from 3 to 35 years. The ordinary sale or retirement of PPE for these assets could result in a gain or loss. Depreciation of PPE related to operations for which regulatory accounting is applicable is provided for primarily on the straight-line method at FERC-prescribed rates over estimated useful lives of 5 to 62 years. Reflecting the application of composite depreciation, gains and losses from the ordinary sale or retirement of PPE for these assets are not recognized in earnings and generally do not impact PPE, net. Note 4 contains more information regarding the Partnership's PPE.

Impairment of Long-lived Assets

The Partnership evaluates long-lived assets for impairment when, in management's judgment, events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. When such a determination has been made, management's estimate of undiscounted future cash flows attributable to the

remaining economic useful life of the asset is compared to the carrying amount of the asset to determine whether an impairment has occurred. If an impairment of the carrying value has occurred, the amount of impairment recognized in the financial statements is determined by estimating the fair value of the assets and recording a loss to the extent that the carrying amount exceeds the estimated fair value.

Capitalized Interest and Allowance for Funds Used During Construction (AFUDC)

The Partnership records capitalized interest, which represents the cost of borrowed funds used to finance construction activities for operations where regulatory accounting is not applicable. The Partnership records AFUDC, which represents the cost of funds, including equity funds, applicable to regulated natural gas transmission plant under construction as permitted by FERC regulatory practices, in connection with the Partnership's operations where regulatory accounting is applicable. Capitalized interest and the allowance for borrowed funds used during construction are recognized as a reduction to *Interest expense* and the allowance for equity funds used during construction is included in *Miscellaneous other income, net* within the Consolidated Statements of Income. The following table summarizes capitalized interest and the allowance for borrowed funds and allowance for equity funds used during construction (in millions):

	For the Year Ended December 31,		
	2011	2010	2009
Capitalized interest and allowance for borrowed funds used during construction	\$ 2.0	\$ 4.2	\$ 10.3
Allowance for equity funds used during construction	0.6	0.4	0.4

Income Taxes

The Partnership is not a taxable entity for federal income tax purposes. As such, it does not directly pay federal income tax. The Partnership's taxable income or loss, which may vary substantially from the net income or loss reported in the Consolidated Statements of Income, is includable in the federal income tax returns of each partner. The aggregate difference in the basis of the Partnership's net assets for financial and income tax purposes cannot be readily determined as the Partnership does not have access to the information about each partner's tax attributes related to the Partnership. The subsidiaries of the Partnership directly incur some income-based state taxes which are presented in *Income taxes* on the Consolidated Statements of Income. Note 11 contains more information regarding the Partnership's income taxes.

Revenue Recognition

The maximum rates that may be charged by the operating subsidiaries for their services are established through FERC's cost-based rate-making process, however rates charged by the operating subsidiaries may be less than those allowed by FERC. Revenues from the transportation and storage of gas are recognized in the period the service is provided based on contractual terms and the related volumes transported or stored. In connection with some PAL and interruptible storage service agreements, cash is received at inception of the service period resulting in the recording of deferred revenues which are recognized in revenues over the period the services are provided. At December 31, 2011 and 2010, the Partnership had deferred revenues of \$8.4 million and \$5.6 million related to PAL and interruptible storage services and \$6.5 million and \$7.4 million related to a firm transportation agreement that was paid in advance. The deferred revenues related to PAL and interruptible storage services will be recognized in 2012 and 2013 and the deferred revenues related to the firm transportation agreement will be recognized through 2018.

Retained fuel is recognized in revenues at market prices in the month of retention for operations where regulatory accounting is not applicable. The related fuel consumed in providing transportation services is recorded in *Fuel and gas transportation* expenses at market prices in the month consumed. Customers may elect to pay cash for the cost of fuel used in providing transportation services instead of having fuel retained in-kind. Retained fuel included in Gas transportation on the *Consolidated Statements of Income* for the years ended December 31, 2011, 2010 and 2009 was \$105.6 million, \$114.2 million and \$77.5 million.

Under FERC regulations, certain revenues that the operating subsidiaries collect may be subject to possible refunds to their customers. Accordingly, during a rate case, estimates of rate refund liabilities are recorded considering regulatory proceedings, advice of counsel and estimated risk-adjusted total exposure, as well as other factors. At December 31, 2011 and 2010, there were no liabilities for any open rate case recorded on the Consolidated Balance Sheets.

Asset Retirement Obligations

The accounting requirements for existing legal obligations associated with the future retirement of long-lived assets require entities to record the fair value of a liability for an asset retirement obligation in the period during which the liability is incurred. The liability is initially recognized at fair value and is increased with the passage of time as accretion expense is recorded, until the liability is ultimately settled. An amount corresponding to the amount of the initial liability is capitalized as part of the carrying amount of the related long-lived asset and depreciated over the useful life of that asset. Note 5 contains more information regarding the Partnership's asset retirement obligations.

Unit-Based and Other Long-Term Compensation

The Partnership provides awards of phantom common units (Phantom Common Units) to certain employees under its Long-Term Incentive Plan (LTIP). The Partnership also provides to certain employees awards of unit appreciation rights (UARs) and long-term cash bonuses (Long-Term Cash Bonuses) under the Boardwalk Pipeline Partners Unit Appreciation Rights and Cash Bonus Plan, which was established in 2010. Prior to 2010, awards of phantom general partner units (Phantom GP units) were made under the Partnership's Strategic Long-Term Incentive Plan (SLTIP).

The Partnership measures the cost of an award issued in exchange for employee services based on the grant-date fair value of the award, or the stated amount in the case of the Long-Term Cash Bonuses. All outstanding awards are either required or expected to be settled in cash and are classified as a liability until settlement. The unit-based compensation awards are remeasured each reporting period until the final amount of awards is determined. The related compensation expense, less applicable estimates of forfeitures, is recognized over the period that employees are required to provide services in exchange for the awards, usually the vesting period. Note 9 contains additional information regarding the Partnership's unit-based and other long-term compensation.

Partner Capital Accounts

For purposes of maintaining capital accounts, items of income and loss of the Partnership are allocated among the partners each year, or portion thereof, in accordance with the partnership agreement. Generally, net income for each period is allocated among the partners based on their respective ownership interests after deducting any priority allocations in the form of cash distributions paid to the general partner as the holder of IDRs.

Derivative Financial Instruments

The Partnership use futures, swaps, and option contracts (collectively, derivatives) to hedge exposure to various risks, including natural gas commodity and interest rate risk, which are reported at fair value. The effective portion of the related unrealized gains and losses resulting from changes in fair values of the derivatives contracts designated as cash flow hedges are deferred as a component of accumulated other comprehensive income (AOCI). The deferred gains and losses are recognized in earnings when the hedged anticipated transactions affect earnings. Changes in fair value of derivatives that are not designated as cash flow hedges are recognized in earnings in the periods that those changes in fair value occur.

The changes in fair values of the derivatives designated as cash flow hedges are expected to, and do, have a high correlation to changes in value of the anticipated transactions. Each reporting period the Partnership measures the effectiveness of the cash flow hedge contracts. To the extent the changes in the fair values of the hedge contracts do not effectively offset the changes in the estimated cash flows of the anticipated transactions, the ineffective portion of the hedge contracts is currently recognized in earnings. If it becomes probable that the anticipated transactions will not occur, hedge accounting would be terminated and changes in the fair values of the associated

derivative financial instruments would be recognized currently in earnings. The Partnership did not discontinue any cash flow hedges during the years ended December 31, 2011 and 2010.

The effective component of gains and losses resulting from changes in fair values of the derivatives designated as cash flow hedges are deferred as a component of AOCI. The deferred gains and losses associated with the anticipated operational sale of gas reported as current *Gas stored underground* are recognized in operating revenues when the anticipated transactions affect earnings. In situations where continued reporting of a loss in AOCI would result in recognition of a future loss on the combination of the derivative and the hedged transaction, the loss is required to be immediately recognized in earnings for the amount that is not expected to be recovered. No such losses were recognized in the years ended December 31, 2011 and 2010. The Partnership had no outstanding derivatives at December 31, 2011. Note 8 contains more information regarding the Partnership's derivative financial instruments.

Fair Value Measurements

Fair value refers to an exit price that would be received to sell an asset or paid to transfer a liability in an orderly transaction in the principal market in which the reporting entity transacts based on the assumptions market participants would use when pricing the asset or liability assuming its highest and best use. A fair value hierarchy has been established that prioritizes the information used to develop those assumptions giving priority, from highest to lowest, to quoted prices in active markets for identical assets and liabilities (Level 1); observable inputs not included in Level 1, for example, quoted prices for similar assets and liabilities (Level 2); and unobservable data (Level 3), for example, a reporting entity's own internal data based on the best information available in the circumstances.

The Partnership's financial statements and certain disclosures include fair value measurements. Notes 4, 5, 8, 9 and 12 contain more information regarding the Partnership's fair value measurements.

Goodwill

In September 2011, the Financial Accounting Standards Board issued Accounting Standards Update 2011-08 (ASU 2011-08), which amended the rules for testing goodwill for impairment. Under the new rules, an entity has the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. In accordance with new GAAP requirements, beginning in 2011, the Partnership first performs a qualitative assessment to determine whether events or circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If indications are that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the Partnership performs a quantitative analysis to measure whether the fair value of the reporting unit is less than its carrying amount. If the fair value is less than the carrying amount an additional step is taken to measure the amount of goodwill impairment, if any. The Partnership also performs a quantitative assessment, other than annually on December 31, whenever events or changes in circumstances indicate that more likely than not the fair value of a reporting unit is less than its carrying amount.

As of December 31, 2011, the Partnership assessed qualitative factors to determine whether it was more likely than not that the fair value of the reporting unit associated with the Partnership's goodwill was less than its carrying amount. The qualitative factors considered included a comparison of key drivers of the fair value of the reporting unit, such as the Partnership's five-year financial plan operating results, the long-term outlook for growth in natural gas demand in the United States, industry and market considerations, macroeconomic conditions and specific events related to the reporting unit. The Partnership concluded that more likely than not the fair value of the reporting unit associated with the Partnership's goodwill was not less than its carrying amount. Accordingly, the quantitative goodwill impairment analysis was not performed and no impairment of goodwill was recorded during 2011.

Prior to 2011, the Partnership performed an annual quantitative review of goodwill for impairment on December 31, and whenever events or changes in circumstances indicated that carrying amount of goodwill may not be recoverable. No impairment of goodwill was recorded during 2010 or 2009.

Note 3: Commitments and Contingencies

Legal Proceedings and Settlements

The Partnership's subsidiaries are parties to various legal actions arising in the normal course of business. Management believes the disposition of these outstanding legal actions will not have a material impact on the Partnership's financial condition, results of operations or cash flows.

Environmental and Safety Matters

The operating subsidiaries are subject to federal, state, and local environmental laws and regulations in connection with the operation and remediation of various operating sites. As of December 31, 2011, and 2010, the Partnership had an accrued liability of approximately \$8.8 million and \$11.2 million related to assessment and/or remediation costs associated with the historical use of polychlorinated biphenyls, petroleum hydrocarbons and mercury, groundwater protection measures and other costs. The liability represents management's estimate of the undiscounted future obligations based on evaluations and discussions with counsel and operating personnel and the current facts and circumstances related to these matters. The related expenditures are expected to occur over the next nine years. As of December 31, 2011, and 2010, approximately \$2.2 million and \$3.6 million were recorded in *Other current liabilities* and approximately \$6.6 million and \$7.6 million were recorded in *Other Liabilities and Deferred Credits*.

Clean Air Act

The Partnership's pipelines are subject to the Clean Air Act (CAA) and the CAA Amendments of 1990 (Amendments) which added significant provisions to the CAA. The Amendments require the Environmental Protection Agency (EPA) to promulgate new regulations pertaining to mobile sources, air toxics, areas of ozone non-attainment, greenhouse gases and regulations affecting reciprocating engines subject to Maximum Achievable Control Technology (MACT). The operating subsidiaries presently operate two facilities in areas affected by non-attainment requirements for the current ozone standard (eight-hour standard). If the EPA designates additional new non-attainment areas or promulgates new air regulations where the Partnership operates, the cost of additions to PPE is expected to increase. The Partnership has assessed the impact of the CAA on its facilities and does not believe compliance with these regulations will have a material impact on its financial condition, results of operations or cash flows.

In 2008, the EPA adopted regulations lowering the 8-hour ozone standard relevant to non-attainment areas. Under the regulations, new non-attainment areas were to be identified which may have required additional emission controls for compliance at as many as 12 facilities operated by the operating subsidiaries. The EPA subsequently proposed to lower the 8-hour ozone standard again in 2011, but instead withdrew the proposed revision and presently intends to proceed with non-attainment area designations according to the 2008 standard. The EPA expects to finalize the initial non-attainment area designations by mid-2012. The 8-hour ozone standard is due for review in 2013. The EPA has stated that any necessary revisions to the standard will be proposed in the fall of 2013, with final rulemaking in 2014. These revisions could lower the 8-hour ozone standard set in 2008 with a compliance deadline between 2014 and 2031. The Partnership continues to monitor this regulation relative to potentially impacted facilities and associated costs for compliance.

In 2011, the Partnership filed reports with the EPA regarding greenhouse gas emissions from its compressor stations, pursuant to final rules issued by the EPA regarding the reporting of greenhouse gas emissions from sources in the U.S. that annually emit 25,000 or more metric tons of greenhouse gases, including carbon dioxide, methane and others. Additionally, the Partnership conducted various facility surveys across its entire system to comply with the EPA's greenhouse gas emission calculations and reporting regulations and will continue to do so annually as required by the rule. Some states have also adopted laws regulating greenhouse gas emissions, although none of the states in which the Partnership operates have adopted such laws. The new federal rules and determinations regarding greenhouse gas emissions have not had, and are not expected to have, a material effect on the Partnership's financial condition, results of operations or cash flows.

In 2010, the EPA adopted regulations requiring further emission controls for air toxics, specifically formaldehyde, from certain compression engines utilizing MACT. The Partnership estimates that certain of its compression engines will require the installation of certain emission controls by late 2013. The Partnership does not believe the regulation will have a material effect on its financial condition, results of operations or cash flows.

Lease Commitments

The Partnership has various operating lease commitments extending through the year 2018 generally covering office space and equipment rentals. Total lease expense for the years ended December 31, 2011, 2010 and 2009 were approximately \$4.5 million, \$4.0 million and \$4.8 million. The following table summarizes minimum future commitments related to these items at December 31, 2011 (in millions):

2012	\$ 4.4
2013	4.1
2014	3.4
2015	3.2
2016	3.1
Thereafter	<u>1.0</u>
Total	<u>\$ 19.2</u>

Commitments for Construction

The Partnership's future capital commitments are comprised of binding commitments under purchase orders for materials ordered but not received and firm commitments under binding construction service agreements. The commitments as of December 31, 2011, were approximately \$16.7 million, all of which are expected to be settled in 2012.

Pipeline Capacity Agreements

The Partnership's operating subsidiaries have entered into pipeline capacity agreements with third-party pipelines that allow the subsidiaries to transport gas to off-system markets on behalf of customers. The Partnership incurred expenses of \$9.8 million, \$11.1 million and \$10.8 million related to pipeline capacity agreements for the years ended December 31, 2011, 2010 and 2009. The future commitments related to pipeline capacity agreements as of December 31, 2011 were (in millions):

2012	\$ 9.0
2013	8.7
2014	8.3
2015	7.7
2016	6.7
Thereafter	<u>8.1</u>
Total	<u>\$ 48.5</u>

Note 4: Property, Plant and Equipment (PPE)

The following table presents the Partnership's PPE as of December 31, 2011 and 2010 (in millions):

Category	2011 Class Amount	Weighted- Average Useful Lives (Years)	2010 Class Amount	Weighted- Average Useful Lives (Years)
Depreciable plant:				
Transmission	\$ 6,365.7	38	\$ 6,282.2	37
Storage	275.8	45	250.4	46
Gathering	90.0	19	88.5	19
General	126.4	18	121.2	18
Rights of way and other	112.7	31	110.0	30
Total utility depreciable plant	6,970.6	37	6,852.3	37
Non-depreciable:				
Construction work in progress	110.4		109.9	
Storage	44.7		48.4	
Land	18.1		16.9	
Other	16.3		16.3	
Total other	189.5		191.5	
Total PPE	7,160.1		7,043.8	
Less: accumulated depreciation	997.1		785.8	
Total PPE, net	\$ 6,163.0		\$ 6,258.0	

The non-depreciable assets were not included in the calculation of the weighted-average useful lives.

The Partnership holds undivided interests in certain assets, including the Bistineau storage facility of which the Partnership owns 92%, the Mobile Bay Pipeline of which the Partnership owns 64% and offshore and other assets, comprised of pipeline and gathering assets in which the Partnership holds various ownership interests. The proportionate share of investment associated with these interests has been recorded as PPE on the balance sheets. The Partnership records its portion of direct operating expenses associated with the assets in *Operation and maintenance expense*. The following table presents the gross PPE investment and related accumulated depreciation for the Partnership's undivided interests as of December 31, 2011 and 2010 (in millions):

	2011		2010	
	Gross PPE Investment	Accumulated Depreciation	Gross PPE Investment	Accumulated Depreciation
Bistineau storage	\$ 57.5	\$ 11.9	\$ 56.0	\$ 10.1
Mobile Bay Pipeline	11.8	2.5	11.3	2.1
Offshore and other assets	19.0	12.6	19.2	12.4
Total	\$ 88.3	\$ 27.0	\$ 86.5	\$ 24.6

Asset Dispositions and Impairments***Materials and Supplies***

The Partnership holds materials and supplies comprised of pipe, valves, fittings and other materials to support its ongoing operations and for potential future growth projects. In 2011, the Partnership determined that a portion of the materials and supplies would not be used given the types of projects the Partnership would likely

pursue under its new growth strategy and the costs to carry and maintain the materials. As a result, the Partnership recognized an impairment charge of \$28.8 million to adjust the carrying amount of those materials and supplies to an estimated fair value of \$6.4 million. The fair value of the materials was determined by obtaining information from brokers, resellers and distributors of these types of materials which are considered Level 3 inputs under the fair value hierarchy. The materials were sold for total proceeds of approximately \$8.3 million, resulting in a net realized gain of \$2.9 million. However, due to the terms of the sale for a portion of the materials, \$3.7 million of gains will not be recognized until the purchaser takes possession of the materials. The remaining amount, a loss of \$0.8 million, was recognized in 2011. In 2010, the Partnership agreed to sell pipe materials with a book value of \$11.5 million for estimated consideration of approximately \$8.2 million and recorded an impairment charge of \$3.3 million. The fair value measurement of the pipe materials was based on Level 3 inputs under the fair value hierarchy. At December 31, 2011, the Partnership held approximately \$22.1 million of materials and supplies which was reflected in *Other Assets* on the Consolidated Balance Sheets.

Gas Sales

In 2011, the Partnership recognized a gain of \$9.2 million from the sale of approximately 4.5 billion cubic feet (Bcf) of gas stored underground with a book value of \$10.3 million that became available for sale due to a change in the storage working gas needed to support operations and no-notice services. In 2010, the Partnership recognized a gain of \$17.5 million from the sale of approximately 5.5 Bcf of gas stored underground with a book value of \$12.5 million which became available for sale as a result of Phase III of the Western Kentucky Storage Expansion and a reduction in the amount of gas needed to support no-notice services. The gains related to these gas sales were recorded in *Net (gain)loss on disposal of operating assets*.

Carthage Compressor Station Incident

In February 2011, a fire occurred at one of the Partnership's compressor stations near Carthage, Texas, which caused significant damage to the compressor building, the compressor units and related equipment housed in the building. The cost to repair the building facilities and replace equipment damaged by the fire was approximately \$18.1 million. The Partnership has insurance which will cover the costs incurred to restore the damaged equipment and facilities, subject to a \$5.0 million deductible. In 2011, the Partnership recognized expenses of \$5.0 million for the amount of costs incurred which were subject to the deductible. The Partnership received a partial payment from insurance carriers of \$4.6 million during 2011. At December 31, 2011, the Partnership recorded a receivable of \$4.3 million for insurance recoveries it expects to receive in 2012.

Bistineau Storage Gas Loss

In 2011, the Partnership completed a series of tests to verify the quantity of gas stored at its Bistineau storage facility. These tests indicated that a gas loss of approximately 6.7 Bcf occurred at the facility. As a result, the Partnership recorded a charge to *Fuel and gas transportation expense* of \$3.7 million to recognize the loss in base gas which had a carrying value of \$0.53 per MMBtu. The Partnership has not yet determined the root cause of the gas loss or whether the gas will need to be replaced.

Overton Lateral

In 2010, the Partnership completed the sale of certain of its gathering assets in the Overton Field area in northeastern Texas for a nominal amount. Prior to the sale, the Partnership recognized an impairment loss of approximately \$2.2 million, representing the net book value of the assets.

Note 5: Asset Retirement Obligations (ARO)

Pursuant to federal regulations, the Partnership has a legal obligation to cut and purge any pipeline that will remain in place after abandonment and to remove offshore platforms after the related gas flows have ceased. The Partnership has identified and recorded legal obligations associated with the abandonment of offshore pipeline assets and certain onshore facilities as well as abatement of asbestos consisting of removal, transportation and disposal when removed from certain compressor stations and meter station buildings. Legal obligations exist for the main

pipeline and certain other Partnership assets, however the fair value of the obligations cannot be determined because the lives of the assets are indefinite and therefore cash flows associated with retirement of the assets cannot be estimated with the degree of accuracy necessary to establish a liability for the obligations.

The following table summarizes the aggregate carrying amount of the Partnership's ARO (in millions):

	<u>2011</u>	<u>2010</u>
Balance at beginning of year	\$ 18.7	\$ 18.0
Liabilities recorded	1.4	-
Liabilities settled	(3.5)	(0.3)
Accretion expense	<u>0.9</u>	<u>1.0</u>
Balance at end of year	17.5	18.7
Less: Current portion of asset retirement obligations	<u>(0.8)</u>	<u>(1.5)</u>
Long-term asset retirement obligations	<u>\$ 16.7</u>	<u>\$ 17.2</u>

The Partnership believes that an ARO exists for the Texas Gas corporate office building constructed in Owensboro, Kentucky, in 1962. Under the legal requirements enacted by the EPA during 1973, Texas Gas became legally obligated to dismantle and remove the asbestos from its office building at the end of its useful life, estimated to range from 2112 to 2162. The Partnership believes that the spray-applied asbestos can be maintained in place indefinitely, if undisturbed by following written maintenance procedures. The Partnership believes that the fair value of any liability relating to future remediation is not material to its financial position, results of operations or cash flows and that any costs incurred for this remediation would be recoverable in its rates.

For the Partnership's operations where regulatory accounting is applicable, depreciation rates for PPE are comprised of two components. One component is based on economic service life (capital recovery) and the other is based on estimated costs of removal (as a component of negative salvage) which is collected in rates and does not represent an existing legal obligation. The Partnership has reflected \$54.5 million and \$51.7 million as of December 31, 2011 and 2010, in the accompanying Consolidated Balance Sheets as *Provision for other asset retirement* related to the estimated cost of removal collected in rates.

Note 6: Regulatory Assets and Liabilities

The amounts recorded as regulatory assets and liabilities in the Consolidated Balance Sheets as of December 31, 2011 and 2010, are summarized in the table below. The table also includes amounts related to unamortized debt expense and unamortized discount on long-term debt. While these amounts are not regulatory assets and liabilities, they are a critical component of the embedded cost of debt financing utilized in the Texas Gas rate proceedings. The tax effect of the equity component of AFUDC represents amounts recoverable from rate payers for the tax effects created prior to the 2005 change in the tax status of Boardwalk Pipelines and its election to be taxed as a partnership. Certain amounts in the table are reflected as a negative, or a reduction, to be consistent with the regulatory books of account. The period of recovery for the regulatory assets included in rates varies from one to sixteen years. The remaining period of recovery for regulatory assets not yet included in rates would be determined in future rate proceedings. None of the regulatory assets shown below were earning a return as of December 31, 2011 and 2010 (in millions):

	<u>2011</u>	<u>2010</u>
Regulatory Assets:		
Pension	\$ 10.6	\$ 10.6
Tax effect of AFUDC equity	4.7	5.1
Unamortized debt expense and premium on reacquired debt	15.4	7.9
Postretirement benefits other than pension	-	4.2
Fuel tracker	9.8	7.1
Total regulatory assets	<u>\$ 40.5</u>	<u>\$ 34.9</u>
Regulatory Liabilities:		
Cashout and fuel tracker	\$ 0.5	\$ 0.3
Provision for other asset retirement	54.5	51.7
Unamortized discount on long-term debt	(2.5)	(2.3)
Postretirement benefits other than pension	29.8	23.7
Other	0.3	0.4
Total regulatory liabilities	<u>\$ 82.6</u>	<u>\$ 73.8</u>

Note 7: Financing

Long-Term Debt

The following table presents all long-term debt issues outstanding as of December 31, 2011 and 2010 (in millions):

	<u>2011</u>	<u>2010</u>
Notes and Debentures:		
Boardwalk Pipelines		
5.88% Notes due 2016	\$ 250.0	\$ 250.0
5.50% Notes due 2017	300.0	300.0
5.20% Notes due 2018	185.0	185.0
5.75% Notes due 2019	350.0	350.0
Gulf South		
5.75% Notes due 2012	225.0	225.0
5.05% Notes due 2015	275.0	275.0
6.30% Notes due 2017	275.0	275.0
Texas Gas		
5.50% Notes due 2013	-	250.0
4.60% Notes due 2015	250.0	250.0
4.50% Notes due 2021	440.0	-
7.25% Debentures due 2027	100.0	100.0
Total notes and debentures	<u>2,650.0</u>	<u>2,460.0</u>
Revolving Credit Facility:		
Boardwalk Pipelines	100.0	285.0
Gulf South	228.5	228.5
Texas Gas	130.0	190.0
Total revolving credit facility	<u>458.5</u>	<u>703.5</u>
Subordinated Loan Agreement with BPHC	<u>100.0</u>	<u>100.0</u>
	3,208.5	3,263.5
Less: unamortized debt discount	(9.8)	(11.2)
Total Long-Term Debt	<u><u>\$ 3,198.7</u></u>	<u><u>\$ 3,252.3</u></u>

Maturities of the Partnership's long-term debt for the next five years and in total thereafter are as follows (in millions):

2012	\$ -
2013	783.5
2014	-
2015	525.0
2016	250.0
Thereafter	1,650.0
Total long-term debt	<u><u>\$ 3,208.5</u></u>

The Partnership has \$458.5 million of loans outstanding under its revolving credit facility, having a maturity date of June 29, 2012, and \$100.0 million of loans outstanding under the Subordinated Loan Agreement which mature initially on December 29, 2012. Amounts outstanding under the revolving credit facility are extendable by the Partnership for an additional year and the maturity date of the Subordinated Loans may be extended by a year if the Partnership elects to extend the term of the revolving credit facility. As a result, this debt is classified as long-term on the *Balance Sheets* and included in the 2013 maturities. The Partnership also has \$225.0 million of notes maturing in August 2012. These notes are included in the 2013 maturities and classified as long-term debt on the *Balance Sheets* since the Partnership expects to refinance these notes on a long-term basis and there

is adequate available capacity under the revolving credit facility to extend the amount that would otherwise come due in less than a year.

Notes and Debentures

During the 2009 to 2011 period, the Partnership completed the following debt issuances (in millions, except interest rates):

Date of Issuance	Issuing Subsidiary	Amount of Issuance⁽¹⁾	Purchaser Discounts and Expenses	Net Proceeds	Interest Rate	Maturity Date	Interest Payable
January and June 2011	Texas Gas	\$440.0	\$2.4	\$437.6 ⁽²⁾	4.50%	February 1, 2021	February 1 and August 1
August 2009	Boardwalk Pipelines	\$350.0	\$3.3	\$346.7 ⁽³⁾	5.75%	September 15, 2019	March 15 and September 15

- (1) BPHC waived the mandatory prepayment provisions under the Subordinated Loan Agreement, described below, that would have required prepayment of the Subordinated Loans as a result of these issuances.
- (2) The net proceeds of these offerings were used to reduce borrowings under the Partnership's revolving credit facility and to redeem Texas Gas' 5.50% notes due April 1, 2013 (2013 Notes).
- (3) The net proceeds were used to directly and indirectly fund the Partnership's capital projects.

The Partnership's notes and debentures are redeemable, in whole or in part, at the Partnership's option at any time, at redemption prices equal to the greater of 100% of the principal amount of the notes to be redeemed or a "make whole" redemption price based on the remaining scheduled payments of principal and interest discounted to the date of redemption at a rate equal to the Treasury rate plus 20 to 50 basis points depending upon the particular issue of notes, plus accrued and unpaid interest, if any. Other customary covenants apply, including those concerning events of default. As of December 31, 2011 and 2010, the weighted-average interest rate of the Partnership's notes and debentures was 5.69% and 5.89%.

The indentures governing the notes and debentures have restrictive covenants which provide that, with certain exceptions, neither the Partnership nor any of its subsidiaries may create, assume or suffer to exist any lien upon any property to secure any indebtedness unless the debentures and notes shall be equally and ratably secured. All debt obligations are unsecured. At December 31, 2011, Boardwalk Pipelines and its operating subsidiaries were in compliance with their debt covenants.

Redemption of Notes

In February 2011, the Partnership redeemed \$135.0 million of 2013 Notes at a premium of \$11.8 million and in July 2011, redeemed the remaining \$115.0 million at a premium of \$9.2 million. The Partnership had unamortized discounts and deferred offering costs of \$1.1 million related to the 2013 Notes which were redeemed. Due to the application of regulatory accounting, approximately \$8.9 million of the premium and unamortized discounts related to the 2013 Notes were recognized as a regulatory asset, and will be amortized over the life of the Texas Gas 4.50% notes due February 1, 2021. A \$7.4 million loss on the early extinguishment of debt was recognized in the first quarter 2011 and an additional loss of \$5.8 million was recognized in the third quarter 2011.

Revolving Credit Facility

The Partnership has a revolving credit facility which has aggregate lending commitments of \$950.0 million. Outstanding borrowings under the credit facility as of December 31, 2011 and 2010, were \$458.5 million and \$703.5 million with a weighted-average borrowing rate of 0.52% and 0.53%. Subsequent to December 31, 2011, the Partnership repaid \$115.0 million of borrowings, which decreased borrowings to \$343.5 million, resulting in available borrowing capacity of \$606.5 million.

The credit facility contains various restrictive covenants and other usual and customary terms and conditions, including limitations on the payment of cash dividends by the Partnership's subsidiaries and other

restricted payments, the incurrence of additional debt, the sale of assets and sale-leaseback transactions. The financial covenants under the credit facility require the Partnership and its subsidiaries to maintain, among other things, a ratio of total consolidated debt to consolidated EBITDA (as defined in the credit agreement) measured for the previous twelve months of not more than 5.0 to 1.0. The Partnership and its subsidiaries were in compliance with all covenant requirements under the credit facility as of December 31, 2011. The revolving credit facility has a maturity date of June 29, 2012, however all outstanding revolving loans on such date may be converted to term loans having a maturity date of June 29, 2013.

Long-Term Debt – Affiliate

In 2009, Boardwalk Pipelines entered into a Subordinated Loan Agreement with BPHC under which Boardwalk Pipelines borrowed \$200.0 million (Subordinated Loans). The Subordinated Loans bear interest at 8.00% per year, payable semi-annually in June and December, and mature six months after the maturity (including any term-out period) of the revolving credit facility. In the event the Partnership or its subsidiaries issue additional equity securities or incur certain indebtedness, the Subordinated Loans must be prepaid with the net cash proceeds from those issuances; although BPHC may waive such prepayment provision. The Subordinated Loans are subordinated in right of payment to the Partnership's obligations under its revolving credit facility pursuant to the terms of a Subordination Agreement between BPHC and Wachovia Bank, National Association, as representative of the lenders under the revolving credit facility. As of December 31, 2011 and 2010, the Partnership had \$100.0 million outstanding under the Subordinated Loan Agreement with no additional borrowing capacity available.

Common Unit Offering

During the 2009 to 2011 period, the Partnership completed the following issuances and sales of common units (in millions, except the issuance price):

Month of Offering	Number of Common Units	Issuance Price	Less Underwriting Discounts and Expenses	Net Proceeds (including General Partner Contribution)	Common Units Outstanding After Offering	Common Units Held by the Public After Offering
June 2011 ⁽¹⁾	6.0	\$29.33	\$6.0	\$173.6	175.7	73.0
August 2009 ⁽¹⁾	8.1	\$23.00	\$7.0	\$183.1	169.7	55.5
June 2009 ⁽¹⁾⁽²⁾	6.7	\$21.99	\$ -	\$150.0	161.6	47.4

- (1) BPHC waived the mandatory prepayment provisions under the Subordinated Loans that would have required prepayment of the Subordinated Loans as a result of these issuances.
- (2) Sold to BPHC in a private placement.

The proceeds of the offerings were used to reduce borrowings under the Partnership's revolving credit facility and to finance a portion of the Partnership's capital projects. In addition to funds received from the issuance and sale of common units, the general partner concurrently contributed amounts to maintain its 2% interest in the Partnership.

Subsequent to December 31, 2011, the Partnership issued and sold 9.2 million common units to the public. The common units were issued at a price of \$27.55. The Partnership received net proceeds of \$250.2 million after deducting underwriters discount and offering expenses of \$8.5 million and including a \$5.2 million contribution received from the general partner to maintain its 2% interest in the Partnership. The net proceeds were used to repay borrowings under the Partnership's revolving credit facility.

Summary of Changes in Outstanding Units

The following table summarizes changes in the Partnership's common and class B units since January 1, 2009 (in millions):

	Common Units	Class B Units
Balance, January 1, 2009	154.9	22.9
Common units issued and sold to BPHC in a private placement	6.7	-
Common units issued in connection with underwritten offerings	8.1	-
Balance, December 31, 2009 and 2010	169.7	22.9
Common units issued in connection with underwritten offerings	6.0	-
Balance, December 31, 2011	175.7	22.9

Subsequent to December 31, 2011, the Partnership issued 9.2 million common units to the public as discussed above.

Registration Rights Agreement

The Partnership has entered into an Amended and Restated Registration Rights Agreement with BPHC under which the Partnership has agreed to register the resale by BPHC of 27.9 million common units and to reimburse BPHC up to a maximum price of \$0.914 per common unit for underwriting discounts and commissions. In February 2010, BPHC sold 11.5 million common units of the Partnership in a secondary offering and consequently, the Partnership reimbursed BPHC \$10.5 million for underwriting discounts and commissions and incurred other offering costs of approximately \$0.2 million, all of which were recorded against the previously established liability pursuant to the registration rights agreement. As of December 31, 2011 and 2010, the Partnership had an accrued liability of approximately \$16.0 million for future underwriting discounts and commissions that would be reimbursed to BPHC and other registration and offering costs that are expected to be incurred by the Partnership.

Note 8: Derivatives

The Partnership uses futures, swaps and option contracts (collectively, derivatives) to hedge exposure to natural gas commodity price risk related to the future operational sales of natural gas and cash for fuel reimbursement where customers pay cash for the cost of fuel used in providing transportation services as opposed to having fuel retained in kind. This price risk exposure includes approximately \$1.7 million and \$3.6 million of gas stored underground at December 31, 2011 and 2010, which the Partnership owns and carries on its balance sheet as current *Gas stored underground*. Additionally, at December 31, 2010, the Partnership had 4.5 Bcf of gas with a book value of \$10.3 million that had become available for sale as a result of a change in the storage working gas needed to support operations and no-notice services at its Texas Gas subsidiary. The Partnership has also periodically used derivatives as cash flow hedges of interest rate risk in anticipation of debt offerings. At December 31, 2011, the Partnership had no outstanding derivatives.

The Partnership's natural gas derivatives are reported at fair value based on New York Mercantile Exchange (NYMEX) quotes for natural gas futures and options. The NYMEX quotes are deemed to be observable inputs in an active market for similar assets and liabilities and are considered Level 2 inputs for purposes of fair value disclosures. The Partnership has not changed its valuation techniques or inputs during the reporting period.

The Partnership had no outstanding derivatives as of December 31, 2011. The fair values of derivatives existing as of December 31, 2010 were included in the following captions in the Consolidated Balance Sheets (in millions):

	Asset Derivatives				Liability Derivatives			
	December 31, 2011		December 31, 2010		December 31, 2011		December 31, 2010	
	Balance sheet location	Fair Value	Balance sheet location	Fair Value	Balance sheet location	Fair Value	Balance sheet location	Fair Value
Derivatives designated as hedging instruments								
Commodity contracts	Other current assets	\$ -	Other current assets	\$ -	Other current liabilities	\$ -	Other current liabilities	\$ 1.7

The amount of gains and losses from derivatives recognized in the Consolidated Statements of Income for the year ended December 31, 2011, were (in millions):

	Amount of gain/(loss) recognized in AOCI on derivatives (effective portion)	Location of gain/(loss) reclassified from AOCI into income (effective portion)	Amount of gain/(loss) reclassified from AOCI into income (effective portion)	Location of gain/(loss) recognized in income on derivative (in-effective portion and amount excluded from effectiveness testing)	Amount of gain/(loss) recognized in income on derivative (in-effective portion and amount excluded from effectiveness testing)
Derivatives in Cash Flow Hedging Relationship					
Commodity contracts	\$ 3.1	Operating revenues (2)	\$ 1.5	N/A	\$ -
Interest rate contracts (1)	-	Interest expense	(1.7)	N/A	-
	<u>\$ 3.1</u>		<u>\$ (0.2)</u>		<u>\$ -</u>

- (1) Related to amounts deferred in AOCI from Treasury rate locks used in hedging interest payments associated with debt offerings that were settled in previous periods and are being amortized to earnings over the terms of the related interest payments, generally the terms of the related debt.
- (2) \$1.1 million was recorded in *Gas transportation revenues* and \$0.4 million was recorded in *Other Revenues*.

The amount of gains and losses from derivatives recognized in the Consolidated Statements of Income for the year ended December 31, 2010, were (in millions):

Derivatives in Cash Flow Hedging Relationship	Amount of gain/(loss) recognized in AOCI on derivatives (effective portion)	Location of gain/(loss) reclassified from AOCI into income (effective portion)	Amount of gain/(loss) reclassified from AOCI into income (effective portion)	Location of gain/(loss) recognized in income on derivative (in-effective portion and amount excluded from effectiveness testing)	Amount of gain/(loss) recognized in income on derivative (in-effective portion and amount excluded from effectiveness testing)
Commodity contracts	\$ 3.1	Operating revenues (2)	\$ 9.9	Other revenues	\$ 0.1
Commodity contracts	2.9	Net gain (loss) on disposal of operating assets	4.7	N/A	-
Interest rate contracts (1)	-	Interest expense	(1.7)	N/A	-
	<u>\$ 6.0</u>		<u>\$ 12.9</u>		<u>\$ 0.1</u>

- (1) Related to amounts deferred in AOCI from Treasury rate locks used in hedging interest payments associated with debt offerings that were settled in previous periods and are being amortized to earnings over the terms of the related interest payments, generally the terms of the related debt.
- (2) \$4.9 million was recorded in *Gas transportation revenues* and \$5.0 million was recorded in *Other Revenues*.

The amount of gains and losses from derivatives recognized in the Consolidated Statements of Income for the year ended December 31, 2009, were (in millions):

Derivatives in Cash Flow Hedging Relationship	Amount of gain/(loss) recognized in AOCI on derivatives (effective portion)	Location of gain/(loss) reclassified from AOCI into income (effective portion)	Amount of gain/(loss) reclassified from AOCI into income (effective portion)	Location of gain/(loss) recognized in income on derivative (in-effective portion and amount excluded from effectiveness testing)	Amount of gain/(loss) recognized in income on derivative (in-effective portion and amount excluded from effectiveness testing)
Commodity contracts	\$ 10.5	Operating revenues (2)	\$ 18.6	Other revenues	\$ (0.4)
Interest rate contracts (1)	-	Interest expense	(1.7)	N/A	-
	<u>\$ 10.5</u>		<u>\$ 16.9</u>		<u>\$ (0.4)</u>

- (1) Related to amounts deferred in AOCI from Treasury rate locks used in hedging interest payments associated with debt offerings that were settled in previous periods and are being amortized to earnings over the terms of the related interest payments, generally the terms of the related debt.
- (2) \$6.3 million was recorded in *Gas transportation revenues* and \$12.3 million was recorded in *Other Revenues*.

The Partnership has entered into master netting agreements to manage counterparty credit risk associated with its derivatives, however it does not offset on its balance sheets fair value amounts recorded for derivative instruments under these agreements.

Note 9: Employee Benefits

Defined Benefit Retirement Plans

Texas Gas employees hired prior to November 1, 2006, are covered under a non-contributory, defined benefit pension plan (Pension Plan). The Texas Gas Supplemental Retirement Plan (SRP) provides pension benefits for the portion of an eligible employee's pension benefit under the Pension Plan that becomes subject to compensation limitations under the Internal Revenue Code. Collectively, the Partnership refers to the Pension Plan and the SRP as Retirement Plans. The Partnership uses a measurement date of December 31 for its Retirement Plans.

As a result of the Texas Gas rate case settlement in 2006, the Partnership is required to fund the amount of annual net periodic pension cost associated with the Pension Plan, including a minimum of \$3.0 million which is the amount included in rates. In 2011 and 2010, the Partnership funded \$9.0 million and \$9.2 million to the Pension Plan and expects to fund approximately \$9.0 million to the plan in 2012. The Partnership does not anticipate that any Pension Plan assets will be returned to the Partnership during 2012. In 2011 and 2010, the Partnership funded \$0.1 million for payments made under the SRP. The Partnership does not expect to fund this plan in the future until such time as benefits are paid.

The Partnership recognizes in expense each year the actuarially determined amount of net periodic pension cost associated with its Retirement Plans, including a minimum amount of \$3.0 million related to its Pension Plan, in accordance with the 2006 rate case settlement. Texas Gas is permitted to seek future rate recovery for amounts of annual Pension Plan costs in excess of \$6.0 million and is precluded from seeking future recovery of annual Pension Plan costs between \$3.0 million and \$6.0 million. As a result, the Partnership would recognize a regulatory asset for amounts of annual Pension Plan costs in excess of \$6.0 million and would reduce its regulatory asset to the extent that annual Pension Plan costs are less than \$3.0 million. Annual Pension Plan costs between \$3.0 million and \$6.0 million will be charged to expense.

Postretirement Benefits Other Than Pension (PBOP)

Texas Gas provides postretirement medical benefits and life insurance to retired employees who were employed full time, hired prior to January 1, 1996, and have met certain other requirements. In 2011 and 2010, the Partnership made \$0.2 million of contributions to the PBOP plan. The PBOP plan is currently in an overfunded status, therefore the Partnership does not expect to make any contributions to the plan in 2012. The Partnership does not anticipate that any plan assets will be returned to the Partnership during 2012. The Partnership uses a measurement date of December 31 for its PBOP plan.

Projected Benefit Obligation, Fair Value of Assets and Funded Status

The projected benefit obligation, fair value of assets, funded status and the amounts not yet recognized as components of net periodic pension and postretirement benefits cost for the Retirement Plans and PBOP at December 31, 2011 and 2010, were as follows (in millions):

	Retirement Plans		PBOP	
	For the Year Ended December 31,		For the Year Ended December 31,	
	2011	2010	2011	2010
Change in benefit obligation:				
Benefit obligation at beginning of period	\$ 132.5	\$ 122.0	\$ 51.7	\$ 53.2
Service cost	3.9	3.8	0.4	0.5
Interest cost	6.4	6.9	2.6	2.8
Plan participants' contributions	-	-	0.9	1.0
Actuarial loss (gain)	3.0	4.8	1.8	(1.2)
Benefits paid	(5.6)	(5.0)	(3.4)	(4.6)
Benefit obligation at end of period	<u>\$ 140.2</u>	<u>\$ 132.5</u>	<u>\$ 54.0</u>	<u>\$ 51.7</u>
Change in plan assets:				
Fair value of plan assets at beginning of period	\$ 105.5	\$ 90.4	\$ 73.3	\$ 72.8
Actual return on plan assets	3.9	10.8	10.8	3.9
Benefits paid	(5.6)	(5.0)	(3.4)	(4.6)
Company contributions	9.1	9.3	0.2	0.2
Plan participants' contributions	-	-	0.9	1.0
Fair value of plan assets at end of period	<u>\$ 112.9</u>	<u>\$ 105.5</u>	<u>\$ 81.8</u>	<u>\$ 73.3</u>
Funded status	<u>\$ (27.3)</u>	<u>\$ (27.0)</u>	<u>\$ 27.8</u>	<u>\$ 21.6</u>
Items not recognized as components of net periodic cost:				
Prior service cost (credit)	\$ 0.1	\$ 0.1	\$ (31.9)	\$ (39.7)
Net actuarial loss	31.1	25.2	10.2	16.6
Total	<u>\$ 31.2</u>	<u>\$ 25.3</u>	<u>\$ (21.7)</u>	<u>\$ (23.1)</u>

At December 31, 2011 and 2010, the following aggregate information relates only to the underfunded plans (in millions):

	For the Year Ended December 31,	
	2011	2010
Projected benefit obligation	\$ 140.2	\$ 132.5
Accumulated benefit obligation	127.5	119.3
Fair value of plan assets	112.9	105.5

Components of Net Periodic Benefit Cost

Components of net periodic benefit cost for both the Retirement Plans and PBOP for the years ended December 31, 2011, 2010 and 2009 were as follows (in millions):

	Retirement Plans			PBOP		
	For the Year Ended December 31,			For the Year Ended December 31,		
	2011	2010	2009	2011	2010	2009
Service cost	\$ 3.9	\$ 3.8	\$ 3.7	\$ 0.4	\$ 0.5	\$ 0.5
Interest cost	6.4	6.9	7.0	2.6	2.8	3.0
Expected return on plan assets	(8.0)	(7.0)	(5.6)	(3.3)	(3.8)	(3.4)
Amortization of prior service credit	-	-	-	(7.8)	(7.8)	(7.7)
Amortization of unrecognized net loss	1.2	1.5	2.1	0.7	0.9	1.5
Regulatory asset (increase) decrease	-	-	(1.1)	4.2	5.4	5.4
Net periodic benefit cost	<u>\$ 3.5</u>	<u>\$ 5.2</u>	<u>\$ 6.1</u>	<u>\$ (3.2)</u>	<u>\$ (2.0)</u>	<u>\$ (0.7)</u>

Due to the Texas Gas rate case settlement in 2006, the Partnership began to amortize the balance of its regulatory asset for PBOP of approximately \$32.0 million on a straight-line basis over approximately 6 years, resulting in an annual decrease in the regulatory asset. The regulatory asset was fully amortized in 2011. In 2009, the regulatory asset for the Retirement Plans was increased due to the accumulated cost for the year exceeding the expense cap established in the Texas Gas rate case settlement. In accordance with the rate case settlement, Texas Gas is permitted to seek future rate recovery for amounts of annual Pension Plan costs in excess of \$6.0 million.

Estimated Future Benefit Payments

The following table shows benefit payments, which reflect expected future service, as appropriate, which are expected to be paid for both the Retirement Plans and PBOP (in millions):

	Retirement Plans	PBOP
2012	\$ 8.8	\$ 3.7
2013	10.1	3.6
2014	10.8	3.6
2015	11.6	3.5
2016	16.1	3.4
2017-2021	77.5	17.5

Weighted-Average Assumptions

Weighted-average assumptions used to determine benefit obligations for the years ended December 31, 2011 and 2010, were as follows:

	Retirement Plans		PBOP	
	For the Year Ended December 31,		For the Year Ended December 31,	
	2011	2010	2011	2010
Discount rate	4.25%	5.00%	4.70%	5.375%
Rate of compensation increase	4.00%	4.00%	-	-

Weighted-average assumptions used to determine net periodic benefit cost for the periods indicated were as follows:

	Retirement Plans			PBOP		
	For the Year Ended			For the Year Ended		
	December 31,			December 31,		
	2011	2010	2009	2011	2010	2009
Discount rate	5.00%	5.70%	6.30%	5.375%	5.70%	6.30%
Expected return on plan assets	7.50%	7.50%	7.50%	4.64%	5.35%	5.35%
Rate of compensation increase	4.00%	4.00%	4.00%	-	-	-

The long-term rate of return for plan assets was determined based on widely-accepted capital market principles, long-term return analysis for global fixed income and equity markets as well as the active total return oriented portfolio management style. Long-term trends are evaluated relative to market factors such as inflation, interest rates and fiscal and monetary policies, in order to assess the capital market assumptions as applied to the plan. Consideration of diversification needs and rebalancing is maintained.

PBOP Assumed Health Care Cost Trends

Assumed health care-cost-trend rates have a significant effect on the amounts reported for PBOP. A one-percentage-point change in assumed trend rates for health care costs would have had the following effects on amounts reported for the year ended December 31, 2011 (in millions):

<u>Effect of 1% Increase:</u>		<u>2011</u>
Benefit obligation at end of year	\$	1.5
Total of service and interest costs for year		0.1
<u>Effect of 1% Decrease:</u>		
Benefit obligation at end of year	\$	(1.3)
Total of service and interest costs for year		(0.1)

For measurement purposes, health care costs for the plans were assumed to increase 8.5% for 2012-2013, grading down to 5% by 2020, assuming 0.5% annual increments for all participants. For December 31, 2010, health care costs for the plans were assumed to increase 9% for 2011-2012 grading down to 5% in 0.5% annual increments for participants not eligible for Medicare and 8.5% grading down to 5% in 0.5% annual increments for participants eligible for Medicare.

Pension Plan and PBOP Asset Allocation and Investment Strategy

Pension Plan

The Pension Plan investments are held in a trust account and consist of an undivided interest in an investment account of the Loews Corporation Employees Retirement Trust (Master Trust), established by Loews and its participating subsidiaries. Use of the Master Trust permits the commingling of trust assets of the Pension Plan with the assets of the Loews Corporation Cash Balance Retirement Plan for investment and administrative purposes. Although assets of all plans are commingled in the Master Trust, the Custodian maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the participating plans. The net investment income of the investment assets is allocated by the Custodian to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans. The Master Trust assets are measured at fair value. The fair value of the interest in the assets of the Master Trust associated with the Pension Plan as of December 31, 2011 and 2010, was \$112.9 million (or 50.5%) and \$105.5 million (or 50.2%), of the total Master Trust assets.

Equity securities are publicly traded securities which are valued using quoted market prices and are considered a Level 1 investment under the fair value hierarchy. Short-term investments that are actively traded or

have quoted prices, such as money market funds, are considered a Level 1 investment. Fixed income mutual funds are actively traded and valued using quoted market prices and are considered a Level 1 investment. Corporate and other taxable bonds and asset-backed securities are valued using pricing for similar securities, recently executed transactions, cash flow models with yield curves, broker/dealer quotes and other pricing models utilizing observable inputs and are considered Level 2 investments. The limited partnership and other invested assets consist primarily of hedge funds, whose fair value represents the Master Trust's share of the net asset value of each company, as determined by the general partner. Level 2 limited partnership and other invested assets include investments which can be redeemed at net asset value in 90 days or less. The limited partnership investments that contain withdrawal provisions greater than 90 days are considered Level 3 investments.

The following table sets forth by level within the fair value hierarchy a summary of the Master Trust's investments measured at fair value on a recurring basis at December 31, 2011 (in millions):

	Master Trust Assets			
	Level 1	Level 2	Level 3	Total
Equity securities	\$ 32.7	\$ -	\$ -	\$ 32.7
Short-term investments	14.2	-	-	14.2
Fixed income mutual funds	98.4	-	-	98.4
Limited partnerships :				
Hedge funds	-	45.3	14.5	59.8
Private equity	-	-	18.4	18.4
Total investments	<u>\$ 145.3</u>	<u>\$ 45.3</u>	<u>\$ 32.9</u>	<u>\$ 223.5</u>

The following table sets forth by level within the fair value hierarchy a summary of the Master Trust's investments measured at fair value on a recurring basis at December 31, 2010 (in millions):

	Master Trust Assets			
	Level 1	Level 2	Level 3	Total
Equity securities	\$ 115.1	\$ -	\$ -	\$ 115.1
Short-term investments	7.7	-	-	7.7
Asset-backed securities	-	2.0	-	2.0
Limited partnerships:				
Hedge funds	-	45.9	22.5	68.4
Private equity	-	-	16.9	16.9
Total investments	<u>\$ 122.8</u>	<u>\$ 47.9</u>	<u>\$ 39.4</u>	<u>\$ 210.1</u>

The following table presents a reconciliation of the beginning and ending balances of the fair value measurements using significant unobservable inputs (Level 3) for the Master Trust (in millions):

	Limited Partnerships: Hedge Funds	Limited Partnerships: Private Equity
Balance, January 1, 2010	\$ 21.1	\$ 14.5
Actual return on assets still held	2.7	2.1
Actual return on assets sold	0.9	0.3
Purchases, sales and settlements	(2.2)	-
Net transfers in/(out) of Level 3	-	-
Balance, December 31, 2010	\$ 22.5	\$ 16.9
Actual return on assets still held	0.4	1.0
Actual return on assets sold	0.3	(0.2)
Purchases, sales and settlements	(8.7)	0.7
Net transfers in/(out) of Level 3	-	-
Balance, December 31, 2011	\$ 14.5	\$ 18.4

PBOP

The PBOP plan assets are held in a trust and are measured at fair value. Short-term investments that are actively traded or have quoted prices, such as money market or mutual funds, are considered a Level 1 investment. Fixed income mutual funds are actively traded and valued using quoted market prices and are considered Level 1 investments. Tax exempt securities, consisting of municipal securities, corporate and other taxable bonds and asset-backed securities are valued using pricing for similar securities, recently executed transactions, cash flow models with yield curves, broker/dealer quotes and other pricing models utilizing observable inputs and are considered Level 2 investments.

The following table sets forth by level within the fair value hierarchy a summary of the PBOP trust investments measured at fair value on a recurring basis at December 31, 2011 (in millions):

	PBOP Trust Assets			
	Level 1	Level 2	Level 3	Total
Short-term investments	\$ 3.4	\$ -	\$ -	\$ 3.4
Fixed income mutual funds	3.5	-	-	3.5
Asset-backed securities	-	19.4	-	19.4
Corporate and other bonds	-	20.1	-	20.1
Tax exempt securities	-	35.4	-	35.4
Total investments	\$ 6.9	\$ 74.9	\$ -	\$ 81.8

The following table sets forth by level within the fair value hierarchy a summary of the PBOP trust investments measured at fair value on a recurring basis at December 31, 2010 (in millions):

	PBOP Trust Assets			
	Level 1	Level 2	Level 3	Total
Short-term investments	\$ 5.7	\$ -	\$ -	\$ 5.7
United States treasuries	8.6	-	-	8.6
Asset-backed securities	-	8.3	-	8.3
Corporate and other bonds	-	18.1	-	18.1
Tax exempt securities	-	32.5	-	32.5
Limited partnerships	-	-	0.1	0.1
Total investments	<u>\$ 14.3</u>	<u>\$ 58.9</u>	<u>\$ 0.1</u>	<u>\$ 73.3</u>

The following table presents a reconciliation of the beginning and ending balances of the fair value measurements using significant unobservable inputs (Level 3) for the trust (in millions):

	Limited Partnerships
Balance, January 1, 2010	\$ 15.6
Actual return on assets still held	-
Actual return on assets sold	0.5
Purchases, sales and settlements	(16.0)
Net transfers in/(out) of Level 3	-
Balance, December 31, 2010	<u>\$ 0.1</u>
Actual return on assets still held	-
Actual return on assets sold	-
Purchases, sales and settlements	(0.1)
Net transfers in/(out) of Level 3	-
Balance, December 31, 2011	<u><u>\$ -</u></u>

Investment strategy

Pension: The Partnership employs a total-return approach using a mix of equities and fixed income investments to prudently maximize the long-term return on plan assets and generate cash flows adequate to meet plan requirements. The intent of this strategy is to minimize plan expenses by outperforming plan liabilities over the long run. Risk tolerance is established through careful consideration of, among other things, plan liabilities and plan funded status. The investment strategy has been to allocate between 40% and 60% of the investment portfolio to equity and alternative investments, including limited partnerships, with consideration given to market conditions and target asset returns. The investment portfolio contains a diversified blend of fixed income, equity and short term securities. Alternative investments, including limited partnerships, have been used to enhance risk adjusted long term returns while improving portfolio diversification. At December 31, 2011, the pension trust had committed \$3.0 million to future capital calls from various third party limited partnership investments in exchange for an ownership interest in the related partnerships. Derivatives may be used to gain market exposure in an efficient and timely manner. Investment risk is measured and monitored on an ongoing basis through annual liability measurements, periodic asset and liability studies and quarterly investment portfolio reviews.

PBOP: The investment strategy for the PBOP assets is to reduce the volatility of plan investments while protecting the initial investment given the overfunded status of the plan. In 2010, the Partnership redeemed its

limited partnership interests and invested in fixed income securities. At December 31, 2011, all of the PBOP investments were in fixed income securities.

Defined Contribution Plans

Texas Gas employees hired on or after November 1, 2006, and Gulf South employees are provided retirement benefits under a similar defined contribution money purchase plan. The operating subsidiaries also provide 401(k) plan benefits to their employees. Costs related to the Partnership's defined contribution plans were \$7.4 million, \$6.9 million and \$6.6 million for the years ended December 31, 2011, 2010 and 2009.

Long-Term Incentive Compensation Plans

The Partnership grants to selected employees long-term compensation awards under the Long-Term Incentive Plan (LTIP) and the Boardwalk Pipeline Partners Unit Appreciation Rights and Cash Bonus Plan (UAR and Cash Bonus Plan), and previously made grants under the Strategic Long-Term Incentive Plan (SLTIP). These awards are intended to align the interests of the employees with those of the Partnership's unitholders, encourage superior performance, attract and retain employees who are essential for the Partnership's growth and profitability and to encourage employees to devote their best efforts to advancing the Partnership's business over both long and short-term time horizons. The Partnership also makes annual grants of common units to certain of its directors under the LTIP. The Partnership does not expect to make additional grants to employees under the SLTIP, under which substantially all of the available awards have been granted.

LTIP

The Partnership reserved 3,525,000 common units for grants of units, restricted units, unit options and unit appreciation rights to officers and directors of the Partnership's general partner and for selected employees under the LTIP. The Partnership has outstanding phantom common units (Phantom Common Units) which were granted under the plan. Each such grant includes a tandem grant of Distribution Equivalent Rights (DERs); vests on the third anniversary of the grant date; and will be payable to the grantee in cash, but may be settled in common units at the discretion of the Partnership's Board of Directors, upon vesting in an amount equal to the sum of the fair market value of the units (as defined in the plan) that vest on the vesting date, less applicable taxes. The vested amount then credited to the grantee's DER account is payable only in cash, less applicable taxes. The economic value of the Phantom Common Units is directly tied to the value of the Partnership's common units, but these awards do not confer any rights of ownership to the grantee. The fair value of the awards will be recognized ratably over the vesting period and remeasured each quarter until settlement based on the market price of the Partnership's common units and amounts credited under the DERs. The Partnership has not made any grants of units, restricted units, unit options or unit appreciation rights under the plan.

A summary of the status of the Phantom Common Units granted under the Partnership's LTIP as of December 31, 2011 and 2010, and changes during the years ended December 31, 2011 and 2010, is presented below:

	Phantom Common Units	Total Fair Value (in millions)	Weighted- Average Vesting Period (in years)
Outstanding at January 1, 2010 ⁽¹⁾	107,071	\$ 3.5	1.4
Paid	(35,835)	(1.2)	-
Forfeited	(1,653)	-	-
Outstanding at December 31, 2010 ⁽¹⁾	69,583	2.4	1.0
Granted	193,819	5.3	3.0
Paid	(44,069)	(1.5)	-
Forfeited	(1,244)	-	-
Outstanding at December 31, 2011 ⁽¹⁾	218,089 ⁽²⁾	5.3 ⁽³⁾	2.9 ⁽³⁾

- (1) Represents fair value and remaining weighted-average vesting period of outstanding awards at the end of the period.
- (2) Includes 24,270 of Phantom Common Units with a total value of \$0.8 million which vested on December 16, 2011 and were paid in cash on January 20, 2012.
- (3) Excludes the Phantom Common Units that vested on December 16, 2011.

The fair value of the awards at the date of grant was based on the formula contained in the LTIP, including the closing market price of the Partnership's common units on or directly preceding the date of grant. The fair value of the awards at December 31, 2011 and 2010 was based on the closing market price of the common unit on those dates of \$27.67 and \$31.13 plus the accumulated value of the DERs. The fair value of the awards will be recognized ratably over the vesting period and remeasured each quarter until settlement in accordance with the treatment of awards classified as liabilities. The Partnership recorded \$0.3 million, \$1.1 million and \$1.7 million in *Administrative and general* expenses during 2011, 2010 and 2009 for the ratable recognition of the fair value of the Phantom Common Unit awards. The total estimated remaining unrecognized compensation expense related to the Phantom Common Units outstanding at December 31, 2011, was \$5.3 million.

In 2011 and 2010, the general partner purchased 2,000 and 1,500 of the Partnership's common units each year in the open market at a price of \$32.82 and \$29.05 per unit. In 2010, an additional 292 common units were purchased in the open market at a price of \$30.83. These units were granted under the LTIP to the independent directors as part of their director compensation. At December 31, 2011, 3,515,708 units were available for grants under the LTIP.

UAR and Cash Bonus Plan

The UAR and Cash Bonus Plan provides for grants of unit appreciation rights (UARs) and cash bonuses (Long-Term Cash Bonuses) to selected employees of the Partnership.

UARs. The economic value of the UARs is tied to the value of the Partnership's common units, but these awards do not confer any rights of ownership to the grantee. Under the terms of the UAR and Cash Bonus Plan, after the expiration of a restricted period (vesting period) each awarded UAR would become vested and payable in cash to the extent the fair market value (as defined in the plan) of a common unit on such date exceeds the exercise price; which resulting amount may be limited to an applicable dollar cap amount per UAR (UAR Cap) depending on the terms of the award agreement. Each UAR may include a feature whereby the exercise price is reduced by the amount of any cash distributions made by the Partnership with respect to a common unit during the restricted period (DER Adjustment). Except in limited circumstances, upon termination of employment during the restricted period, any outstanding and unvested awards of UARs would be cancelled unpaid. The fair value of the UARs will be recognized ratably over the vesting period, and will be remeasured each quarter until settlement in accordance with the treatment of awards classified as liabilities.

A summary of the outstanding UARs granted under the Partnership's UAR and Cash Bonus Plan as of December 31, 2011 and 2010, and changes during 2011 and 2010 is presented below:

	UARs	Weighted Average Exercise Price	Total Fair Value (in millions)	Weighted- Average Vesting Period (in years)
Outstanding at January 1, 2010	-	-	-	-
Granted ⁽¹⁾	368,956	\$ 30.36	\$ 1.5	3.0
Outstanding at December 31, 2010 ⁽²⁾	368,956	30.36		3.0
Forfeited	(29,609)			
Granted ⁽³⁾	27,551	32.58	0.1	2.8
Granted ⁽⁴⁾	71,277	28.93	0.2	2.5
Granted ⁽⁵⁾	218,342	27.30	1.5	3.0
Outstanding at December 31, 2011 ⁽²⁾	656,517	29.28	3.0	2.3

- (1) Represents the weighted-average exercise price and weighted-average vesting period of awards at grant date. The exercise price for each UAR granted was set at \$30.36, the closing price of the Partnership's common units on the New York Stock Exchange on the day immediately preceding the grant date, and a UAR Cap of \$15.76 was established for each UAR granted on December 16, 2010.
- (2) Represents weighted-average exercise price, remaining weighted-average vesting period and total fair value of outstanding awards at the end of the period.
- (3) Represents the weighted-average exercise price and weighted-average vesting period of awards at grant date. The exercise price for each UAR granted was set at \$32.58, the closing price of the Partnership's common units on the New York Stock Exchange on the day immediately preceding the grant date, and a UAR Cap of \$14.29 was established for each UAR granted on March 31, 2011.
- (4) Represents the weighted-average exercise price and weighted-average vesting period of awards at grant date. The exercise price for each UAR granted was set at \$28.93, the closing price of the Partnership's common units on the New York Stock Exchange on the day immediately preceding the grant date, and a UAR Cap of \$12.67 was established for each UAR granted on June 30, 2011.
- (5) Represents the weighted-average exercise price and weighted-average vesting period of awards at grant date. The exercise price for each UAR granted was set at \$27.30, the closing price of the Partnership's common units on the New York Stock Exchange on the grant date on December 14, 2011. No UAR Cap is applicable to these awards.

The fair value of the UARs granted in December 2011 was based on the computed value of a call on the Partnership's common units at the exercise price. The fair value of the UARs granted prior to December 2011 was determined by calculating the difference between the computed value of a call on the Partnership's common units at the exercise price and a similar call at an exercise price that has been increased to accommodate the UAR Cap. The following assumptions were used as inputs to the Black-Scholes valuation model for grants made during 2011 and 2010:

	December 31, 2011	December 31, 2010
Expected life (years)	2.0 - 3.0	3.0
Risk free interest rate ⁽¹⁾	0.25% - 1.17%	1.0% - 1.1%
Expected volatility ⁽²⁾	34% - 38%	38%

(1) Based on the U.S. Treasury yield curve corresponding to the remaining life of the UAR.

(2) Based on the historical volatility of the Partnership's common units.

The Partnership recorded compensation expense of \$0.4 million and less than \$0.1 million for the years ended December 31, 2011 and 2010, related to the UARs. As of December 31, 2011 and 2010, there was \$2.5 million and \$1.4 million of total unrecognized compensation cost related to the non-vested portion of the UARs.

Long-Term Cash Bonuses. In 2011 and 2010, The Partnership granted to certain employees \$0.4 million and \$1.7 million of Long-Term Cash Bonuses under the UAR and Cash Bonus Plan. Each Long-Term Cash Bonus granted prior to 2011 will become vested and payable to the holder in cash equal to the amount of the grant after the expiration of a three-year restricted period. These grants made in 2011 will vest on the same date as the 2010 grants. Except in limited circumstances, upon termination of employment during the restricted period, any outstanding and unvested awards of Long-Term Cash Bonuses would be cancelled unpaid. The Partnership recorded compensation expense of \$0.5 million and less than \$0.1 million for the year ended December 31, 2011 and 2010, related to the Long-Term Cash Bonuses. As of December 31, 2011 and 2010, there was \$1.3 million and \$1.5 million of total unrecognized compensation cost related to the non-vested portion of the Long-Term Cash Bonuses.

SLTIP

The SLTIP provided for the issuance of up to 500 phantom general partner units (Phantom GP Units) to selected employees of the Partnership and its subsidiaries. Each Phantom GP Unit entitles the holder thereof, upon vesting, to a lump sum cash payment in an amount determined by a formula based on cash distributions made by the Partnership to its general partner during the four quarters preceding the vesting date and the implied yield on the Partnership's common units, up to a maximum of \$50,000 per unit.

A summary of the status of the Partnership's SLTIP as of December 31, 2011 and 2010, and changes during the years ended December 31, 2011 and 2010, is presented below:

	Phantom GP Units	Total Fair Value (in millions)	Weighted-Average Vesting Period (in years)
Outstanding at January 1, 2010 ⁽¹⁾	456.0	\$ 20.6	2.0
Paid	(88.0)	(2.9)	-
Forfeited	(1.0)	-	-
Outstanding at December 31, 2010 ⁽¹⁾	367.0	17.6	1.5
Paid	(83.0)	(3.6)	-
Forfeited	(21.5)	-	-
Outstanding at December 31, 2011 ⁽¹⁾	262.5	12.4	0.8

- (1) Represents fair value and remaining weighted-average vesting period of outstanding awards at the end of the period.

The fair value of the awards at the date of grant was based on the formula contained in the SLTIP and assumptions made regarding potential future cash distributions made to the general partner during the four quarters preceding the vesting date and the future implied yield on the Partnership's common units. The fair value of the awards will be recognized ratably over the vesting period and remeasured each quarter until settlement in accordance with the treatment of awards classified as liabilities. The Partnership recorded \$2.5 million, \$4.9 million and \$3.8 million in *Administrative and general* expenses during 2011, 2010 and 2009 for the ratable recognition of the fair value of the GP Phantom Unit awards. The total estimated remaining unrecognized compensation expense related to the GP Phantom Units outstanding at December 31, 2011, was \$2.8 million. No additional grants of Phantom GP Units are expected to be made under the SLTIP.

Note 10: Cash Distributions and Net Income per Unit

Cash Distributions

The Partnership's cash distribution policy requires that the Partnership distribute to its various ownership interests on a quarterly basis all of its available cash, as defined in its partnership agreement. IDRs, which represent a limited partner ownership interest and are currently held by the Partnership's general partner, represent the contractual right to receive an increasing percentage of quarterly distributions of available cash as follows:

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
		Limited Partner Unitholders (1)	General Partner and IDRs
	Target Amount		
First Target Distribution	up to \$0.4025	98%	2%
Second Target Distribution	above \$0.4025 up to \$0.4375	85%	15%
Third Target Distribution	above \$0.4375 up to \$0.5250	75%	25%
Thereafter	above \$0.5250	50%	50%

- (1) The class B unitholders participate in distributions on a pari passu basis with the Partnership's common units up to \$0.30 per unit per quarter. The class B units do not participate in quarterly distributions above \$0.30 per unit.

The Partnership has declared quarterly distributions per unit to unitholders of record, including holders of common and class B units and the 2% general partner interest and IDRs held by its general partner as follows (in millions, except distribution per unit):

Payment Date	Distribution per Unit	Amount Paid to Common Unitholders	Amount Paid to Class B Unitholder	Amount Paid to General Partner (Including IDRs) (1)
November 17, 2011	\$ 0.5275	\$ 92.7	\$ 6.9	\$ 8.2
August 18, 2011	0.525	92.2	6.9	7.8
May 19, 2011	0.5225	88.6	6.9	7.4
February 24, 2011	0.520	88.2	6.8	7.3
November 8, 2010	0.515	87.4	6.9	6.9
August 9, 2010	0.510	86.5	6.9	6.7
May 10, 2010	0.505	85.8	6.8	6.4
February 22, 2010	0.500	84.8	6.8	6.2
November 9, 2009	0.495	84.0	6.8	5.9
August 10, 2009	0.490	79.2	6.9	5.2
May 11, 2009	0.485	75.1	6.8	4.9
February 23, 2009	0.480	74.4	6.9	4.5

- (1) In 2011, 2010 and 2009, the Partnership paid \$22.3 million, \$18.2 million and \$13.3 million in distributions on behalf of IDRs.

In February 2012, the Partnership declared a quarterly cash distribution to unitholders of record of \$0.53 per unit.

Net Income per Unit

For purposes of calculating net income per unit, net income for the current period is reduced by the amount of available cash that will be distributed with respect to that period. Any residual amount representing undistributed net income (or loss) is assumed to be allocated to the various ownership interests in accordance with the contractual provisions of the partnership agreement.

Under the Partnership's partnership agreement, for any quarterly period, the IDRs participate in net income only to the extent of the amount of cash distributions actually declared, thereby excluding the IDRs from participating in undistributed net income or losses. Accordingly, undistributed net income is assumed to be allocated to the other ownership interests on a pro rata basis, except that the class B units' participation in net income is limited to \$0.30 per unit per quarter. Payments made on account of the Partnership's various ownership interests are determined in relation to actual declared distributions, and are not based on the assumed allocations required under GAAP.

The following table provides a reconciliation of net income and the assumed allocation of net income to the common and class B units for purposes of computing net income per unit for the year ended December 31, 2011, (in millions, except per unit data):

	Total	Common Units	Class B Units	General Partner and IDRs
Net income	\$ 220.0			
Declared distribution	431.6	\$ 371.6	\$ 27.5	\$ 32.5
Assumed allocation of undistributed net loss	(211.6)	(183.2)	(24.2)	(4.2)
Assumed allocation of net income	<u>\$ 220.0</u>	<u>\$ 188.4</u>	<u>\$ 3.3</u>	<u>\$ 28.3</u>
Weighted-average units outstanding		173.3	22.9	
Net income per unit		\$ 1.09	\$ 0.14	

The following table provides a reconciliation of net income and the assumed allocation of net income to the common and class B units for purposes of computing net income per unit for the year ended December 31, 2010, (in millions, except per unit data):

	Total	Common Units	Class B Units	General Partner and IDRs
Net income	\$ 289.4			
Declared distribution	402.6	\$ 347.9	\$ 27.4	\$ 27.3
Assumed allocation of undistributed net loss	(113.2)	(97.7)	(13.2)	(2.3)
Assumed allocation of net income	<u>\$ 289.4</u>	<u>\$ 250.2</u>	<u>\$ 14.2</u>	<u>\$ 25.0</u>
Weighted-average units outstanding		169.7	22.9	
Net income per unit		\$ 1.47	\$ 0.62	

The following table provides a reconciliation of net income and the assumed allocation of net income to the common and class B units for purposes of computing net income per unit for the year ended December 31, 2009 (in millions, except per unit data):

	Total	Common Units	Class B Units	General Partner and IDRs
Net income	\$ 162.7			
Declared distribution	372.7	\$ 323.2	\$ 27.4	\$ 22.1
Assumed allocation of undistributed net loss	(210.0)	(180.3)	(25.5)	(4.2)
Assumed allocation of net income	<u>\$ 162.7</u>	<u>\$ 142.9</u>	<u>\$ 1.9</u>	<u>\$ 17.9</u>
Weighted-average units outstanding		161.6	22.9	
Net income (loss) per unit		\$ 0.88	\$ 0.08	

Note 11: Income Taxes

The Partnership is not a taxable entity for federal income tax purposes. As such, it does not directly pay federal income tax. The Partnership's taxable income or loss, which may vary substantially from the net income or loss reported in the Consolidated Statements of Income, is includable in the federal income tax returns of each partner. The aggregate difference in the basis of the Partnership's net assets for financial and income tax purposes

cannot be readily determined as the Partnership does not have access to the information about each partner's tax attributes. The subsidiaries of the Partnership directly incur some income-based state taxes which are presented in *Income taxes* on the Consolidated Statements of Income.

Following is a summary of the provision for income taxes for the periods ended December 31, 2011, 2010 and 2009 (in millions):

	For the Year Ended December 31,		
	2011	2010	2009
Current expense:			
State	\$ 0.3	\$ 0.3	\$ 0.2
Total	0.3	0.3	0.2
Deferred provision:			
State	0.1	0.2	0.1
Total	0.1	0.2	0.1
Income taxes	\$ 0.4	\$ 0.5	\$ 0.3

The Partnership's tax years 2008 through 2011 remain subject to examination by the Internal Revenue Service and the states in which it operates. There were no differences between the provision at the statutory rate to the income tax provision at December 31, 2011, 2010 and 2009. As of December 31, 2011 and 2010, there were no significant deferred income tax assets or liabilities.

Note 12: Financial Instruments

The following methods and assumptions were used in estimating the Partnership's fair value disclosures for financial instruments:

Cash and Cash Equivalents: For cash and short-term financial assets, the carrying amount is a reasonable estimate of fair value due to the short maturity of those instruments.

Long-Term Debt: The estimated fair value of the Partnership's publicly traded debt is based on quoted market prices at December 31, 2011 and 2010. The fair market value of the debt that is not publicly traded is based on market prices of similar debt at December 31, 2011 and 2010.

Long-Term Debt - Affiliate: Borrowings under a subordinated loan agreement with BPHC were completed in 2009. The estimated fair value is based on market prices of similar debt, adjusted for the affiliated nature of the transaction.

The carrying amount and estimated fair values of the Partnership's financial instruments as of December 31, 2011 and 2010, were as follows (in millions):

	December 31, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial Assets				
Cash and cash equivalents	\$ 11.9	\$ 11.9	\$ 55.0	\$ 55.0
Financial Liabilities				
Long-term debt	\$ 3,098.7	3,337.8	\$ 3,152.3	\$ 3,314.3
Long-term debt – affiliate	100.0	105.8	100.0	106.3

Note 13: Accumulated Other Comprehensive Loss

The following table shows the components of *Accumulated other comprehensive loss* which is included in Partners' Capital on the Consolidated Balance Sheets (in millions):

	As of December 31, 2011	As of December 31, 2010
Loss on cash flow hedges	\$ (10.4)	\$ (13.7)
Deferred components of net periodic benefit cost	(39.0)	(25.8)
Total Accumulated other comprehensive loss	<u>\$ (49.4)</u>	<u>\$ (39.5)</u>

The Partnership estimates that approximately \$3.9 million of net gains reported in AOCI as of December 31, 2011, are expected to be reclassified into earnings within the next twelve months. This amount is comprised of a \$1.7 million decrease to earnings related to cash flow hedges and a \$5.6 million increase to earnings related to net periodic benefit cost. As discussed in Note 8, the Partnership does not have any derivatives outstanding as of December 31, 2011. The loss on cash flow hedges in the table above as of December 31, 2011, is related to losses deferred in AOCI from treasury rate locks that were settled in previous periods and are being amortized over the terms of the related interest payments.

Note 14: Credit Risk*Major Customers*

Operating revenues received from the Partnership's major customer (in millions) and the percentage of total operating revenues earned from that customer were:

	For the Year Ended December 31,					
	2011		2010		2009	
	Revenue	%	Revenue	%	Revenue	%
Devon Gas Services, LP	\$ 134.2	12%	\$ 143.5	13%	\$ 102.6	11%

Gas Loaned to Customers

Natural gas price volatility can cause changes in credit risk related to gas loaned to customers. As of December 31, 2011, the amount of gas owed to the operating subsidiaries due to gas imbalances and gas loaned under PAL agreements was approximately 8.3 TBtu. Assuming an average market price during December 2011 of \$3.14 per MMBtu, the market value of that gas was approximately \$26.1 million. As of December 31, 2010, the amount of gas owed to the operating subsidiaries due to gas imbalances and gas loaned under PAL agreements was approximately 13.0 TBtu. Assuming an average market price during December 2010 of \$4.21 per MMBtu, the market value of this gas at December 31, 2010, would have been approximately \$54.7 million. If any significant customer should have credit or financial problems resulting in a delay or failure to repay the gas owed to the operating subsidiaries, it could have a material adverse effect on the Partnership's financial condition, results of operations or cash flows.

Note 15: Related Party Transactions

Loews provides a variety of corporate services to the Partnership under services agreements, including but not limited to, information technology, tax, risk management, internal audit and corporate development services, plus allocated overheads. The Partnership incurred charges related to these services of \$18.3 million, \$16.8 million and \$17.1 million for the years ended December 31, 2011, 2010 and 2009.

Distributions paid related to limited partner units held by BPHC and the 2% general partner interest and IDRs held by Boardwalk GP were \$273.3 million, \$267.9 million and \$264.2 million for the years ended December 31, 2011, 2010 and 2009.

In December 2011, Boardwalk HP Storage (HP Storage), a joint venture between Boardwalk Pipelines and BPHC acquired Petal Gas Storage, L.L.C., Hattiesburg Gas Storage Company and related entities for approximately \$550.0 million in cash. HP Storage funded the acquisition with borrowings under a new \$200.0 million five-year bank loan and equity contributions from Boardwalk Pipelines and BPHC. BPHC contributed \$280.0 million towards the purchase price for an 80% equity ownership interest in HP Storage and Boardwalk Pipelines contributed \$70.0 million for a 20% equity ownership interest. Gulf South operates the assets of HP Storage on behalf of the joint venture.

Note 16: Supplemental Disclosure of Cash Flow Information (in millions):

	For the Year Ended December 31,		
	2011	2010	2009
Cash paid during the period for:			
Interest (net of amount capitalized) ⁽¹⁾	\$ 171.7	\$ 146.3	\$ 124.4
Income taxes, net	\$ 0.3	\$ 0.4	\$ 0.2
Non-cash adjustments:			
Accounts payable and PPE	\$ 23.8	\$ 29.5	\$ 173.2
Accrued registration rights costs	\$ -	\$ -	\$ 6.1

(1) The 2011 period includes \$21.0 million of premiums paid for the 2013 Notes redemption.

Note 17: Selected Quarterly Financial Data (Unaudited)

The following tables summarize selected quarterly financial data for 2011 and 2010 for the Partnership (in millions, except for earnings per unit):

	2011			
	For the Quarter Ended:			
	December 31	September 30	June 30	March 31
Operating revenues	\$ 296.9	\$ 268.9	\$ 262.0	\$ 311.0
Operating expenses	181.7	176.5	207.4	180.5
Operating income	115.2	92.4	54.6	130.5
Interest expense, net	39.7	39.5	39.5	40.2
Other (income) expense	0.8	5.6	(0.1)	7.1
Income before income taxes	74.7	47.3	15.2	83.2
Income taxes (benefit)	0.1	0.1	-	0.2
Net income	<u>\$ 74.6</u>	<u>\$ 47.2</u>	<u>\$ 15.2</u>	<u>\$ 83.0</u>
Net income per unit:				
Common units	\$ 0.36	\$ 0.23	\$ 0.07	\$ 0.42
Class B units	\$ 0.11	\$ -	\$ (0.16)	\$ 0.20
Total Comprehensive Income	\$ 65.6	\$ 47.0	\$ 15.4	\$ 82.1

	2010			
	For the Quarter Ended:			
	December 31	September 30	June 30	March 31
Operating revenues	\$ 302.0	\$ 257.6	\$ 256.7	\$ 300.5
Operating expenses	174.6	164.5	164.7	173.1
Operating income	127.4	93.1	92.0	127.4
Interest expense, net	38.7	37.1	37.5	37.1
Other (income) expense	(0.3)	-	-	(0.1)
Income before income taxes	89.0	56.0	54.5	90.4
Income taxes (benefit)	0.1	0.2	0.1	0.1
Net income	<u>\$ 88.9</u>	<u>\$ 55.8</u>	<u>\$ 54.4</u>	<u>\$ 90.3</u>
Net income per unit:				
Common units	\$ 0.45	\$ 0.28	\$ 0.28	\$ 0.46
Class B units	\$ 0.23	\$ 0.07	\$ 0.07	\$ 0.26
Total Comprehensive Income	\$ 83.0	\$ 48.2	\$ 47.8	\$ 96.3

Note 18: Guarantee of Securities of Subsidiaries

Boardwalk Pipelines (subsidiary issuer) has issued securities which have been fully and unconditionally guaranteed by the Partnership (parent guarantor). The Partnership's subsidiaries have no significant restrictions on their ability to pay distributions or make loans to the Partnership except as noted in the debt covenants and have no restricted assets at December 31, 2011 and 2010. Note 7 contains additional information regarding the Partnership's debt and related covenants.

The Partnership has provided the following condensed consolidating financial information in accordance with Regulation S-X Rule 3-10, *Financial Statements of Guarantors and Issuers of Guaranteed Securities Registered or Being Registered*.

Condensed Consolidating Balance Sheets as of December 31, 2011
(in millions)

Assets	Parent Guarantor	Subsidiary Issuer	Non- guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Cash and cash equivalents	\$ 0.5	\$ 10.7	\$ 0.7	\$ -	\$ 11.9
Receivables	-	-	126.6	(8.1)	118.5
Gas stored underground	-	-	1.7	-	1.7
Prepayments	-	-	13.3	-	13.3
Other current assets	0.2	-	19.0	(1.8)	17.4
Total current assets	0.7	10.7	161.3	(9.9)	162.8
Investment in consolidated subsidiaries	989.8	5,070.3	-	(6,060.1)	-
Property, plant and equipment, gross	0.6	-	7,159.5	-	7,160.1
Less—accumulated depreciation and amortization	(0.6)	-	(996.5)	-	(997.1)
Property, plant and equipment, net	-	-	6,163.0	-	6,163.0
Other noncurrent assets	0.3	1.4	373.0	-	374.7
Advances to affiliates – noncurrent	2,234.3	-	650.8	(2,885.1)	-
Investment in unconsolidated affiliate	-	70.1	-	-	70.1
Total other assets	2,234.6	71.5	1,023.8	(2,885.1)	444.8
Total Assets	\$ 3,225.1	\$ 5,152.5	\$ 7,348.1	\$ (8,955.1)	\$ 6,770.6

Liabilities & Partners' Capital/Member's Equity	Parent Guarantor	Subsidiary Issuer	Non- guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Payables	\$ 3.4	\$ 0.1	\$ 56.9	\$ (8.1)	\$ 52.3
Advances from affiliates	-	-	-	-	-
Other current liabilities	0.3	15.5	125.7	(1.8)	139.7
Total current liabilities	3.7	15.6	182.6	(9.9)	192.0
Total long-term debt	-	1,280.1	1,918.6	-	3,198.7
Payable to affiliate	16.0	2,885.1	-	(2,885.1)	16.0
Other noncurrent liabilities	0.2	(0.2)	158.7	-	158.7
Total other liabilities and deferred credits	16.2	2,884.9	158.7	(2,885.1)	174.7
Total partners' capital/member's equity	3,205.2	971.9	5,088.2	(6,060.1)	3,205.2
Total Liabilities and Partners' Capital/Member's Equity	\$ 3,225.1	\$ 5,152.5	\$ 7,348.1	\$ (8,955.1)	\$ 6,770.6

Condensed Consolidating Balance Sheets as of December 31, 2010
(in millions)

Assets	Parent Guarantor	Subsidiary Issuer	Non- guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Cash and cash equivalents	\$ -	\$ 52.6	\$ 2.4	\$ -	\$ 55.0
Receivables	-	-	115.2	(9.0)	106.2
Gas stored underground	-	-	3.6	-	3.6
Prepayments	-	-	11.4	-	11.4
Advances to affiliates	-	107.8	-	(107.8)	-
Other current assets	-	-	34.9	(7.9)	27.0
Total current assets	-	160.4	167.5	(124.7)	203.2
Investment in consolidated subsidiaries	799.4	4,940.9	-	(5,740.3)	-
Property, plant and equipment, gross	0.6	-	7,043.2	-	7,043.8
Less—accumulated depreciation and amortization	(0.5)	-	(785.3)	-	(785.8)
Property, plant and equipment, net	0.1	-	6,257.9	-	6,258.0
Other noncurrent assets	-	1.8	417.0	(2.0)	416.8
Advances to affiliates – noncurrent	2,461.4	-	362.2	(2,823.6)	-
Total other assets	2,461.4	1.8	779.2	(2,825.6)	416.8
Total Assets	\$ 3,260.9	\$ 5,103.1	\$ 7,204.6	\$ (8,690.6)	\$ 6,878.0

Liabilities & Partners' Capital/Member's Equity	Parent Guarantor	Subsidiary Issuer	Non- guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Payables	\$ 3.5	\$ 0.3	\$ 101.3	\$ (18.3)	\$ 86.8
Advances from affiliates	-	-	107.8	(107.8)	-
Other current liabilities	-	15.5	112.2	(0.7)	127.0
Total current liabilities	3.5	15.8	321.3	(126.8)	213.8
Total long-term debt	-	1,464.3	1,788.0	-	3,252.3
Payable to affiliate	16.0	2,823.6	-	(2,823.6)	16.0
Other noncurrent liabilities	-	-	154.4	0.1	154.5
Total other liabilities and deferred credits	16.0	2,823.6	154.4	(2,823.5)	170.5
Total partners' capital/member's equity	3,241.4	799.4	4,940.9	(5,740.3)	3,241.4
Total Liabilities and Partners' Capital/Member's Equity	\$ 3,260.9	\$ 5,103.1	\$ 7,204.6	\$ (8,690.6)	\$ 6,878.0

Condensed Consolidating Statements of Income for the Year Ended December 31, 2011
(in millions)

	Parent Guarantor	Subsidiary Issuer	Non- guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Operating revenues:					
Gas transportation	\$ -	\$ -	\$ 1,164.1	\$ (98.6)	\$ 1,065.5
Parking and lending	-	-	12.8	(0.8)	12.0
Gas storage	-	-	49.9	-	49.9
Other	-	-	11.4	-	11.4
Total operating revenues	<u>-</u>	<u>-</u>	<u>1,238.2</u>	<u>(99.4)</u>	<u>1,138.8</u>
Operating cost and expenses:					
Fuel and gas transportation	-	-	202.1	(99.4)	102.7
Operation and maintenance	-	-	168.5	-	168.5
Administrative and general	(0.3)	-	133.0	-	132.7
Other operating costs and expenses	0.3	-	341.9	-	342.2
Total operating costs and expenses	<u>-</u>	<u>-</u>	<u>845.5</u>	<u>(99.4)</u>	<u>746.1</u>
Operating income (loss)	<u>-</u>	<u>-</u>	<u>392.7</u>	<u>-</u>	<u>392.7</u>
Other deductions (income):					
Interest expense	0.1	64.4	86.8	-	151.3
Interest expense - affiliates, net	(31.6)	46.1	(6.5)	-	8.0
Loss on early retirement of debt	-	-	13.2	-	13.2
Interest income	-	-	(0.4)	-	(0.4)
Equity in earnings of subsidiaries	(188.5)	(308.7)	-	497.2	-
Equity losses from unconsolidated affiliate	-	1.1	-	-	1.1
Miscellaneous other income	-	-	(0.9)	-	(0.9)
Total other deductions (income)	<u>(220.0)</u>	<u>(197.1)</u>	<u>92.2</u>	<u>497.2</u>	<u>172.3</u>
Income before income taxes	220.0	197.1	300.5	(497.2)	220.4
Income taxes	<u>-</u>	<u>-</u>	<u>0.4</u>	<u>-</u>	<u>0.4</u>
Net Income	<u>\$ 220.0</u>	<u>\$ 197.1</u>	<u>\$ 300.1</u>	<u>\$ (497.2)</u>	<u>\$ 220.0</u>

Condensed Consolidating Statements of Income for the Year Ended December 31, 2010
(in millions)

	Parent Guarantor	Subsidiary Issuer	Non- guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Operating revenues:					
Gas transportation	\$ -	\$ -	\$ 1,121.6	\$ (106.2)	\$ 1,015.4
Parking and lending	-	-	41.4	(13.3)	28.1
Gas storage	-	-	55.4	-	55.4
Other	-	-	17.9	-	17.9
Total operating revenues	-	-	1,236.3	(119.5)	1,116.8
Operating cost and expenses:					
Fuel and gas transportation	-	-	228.9	(119.5)	109.4
Operation and maintenance	-	-	149.6	-	149.6
Administrative and general	1.3	-	125.3	-	126.6
Other operating costs and expenses	0.4	-	290.9	-	291.3
Total operating costs and expenses	1.7	-	794.7	(119.5)	676.9
Operating income (loss)	(1.7)	-	441.6	-	439.9
Other deductions (income):					
Interest expense	-	64.9	78.0	-	142.9
Interest expense - affiliates, net	(35.0)	44.1	(1.0)	-	8.1
Interest income	-	-	(0.6)	-	(0.6)
Equity in earnings of subsidiaries	(256.1)	(365.1)	-	621.2	-
Miscellaneous other income	-	-	(0.4)	-	(0.4)
Total other deductions (income)	(291.1)	(256.1)	76.0	621.2	150.0
Income before income taxes	289.4	256.1	365.6	(621.2)	289.9
Income taxes	-	-	0.5	-	0.5
Net Income	\$ 289.4	\$ 256.1	\$ 365.1	\$ (621.2)	\$ 289.4

Condensed Consolidating Statements of Income for the Year Ended December 31, 2009
(in millions)

	Parent Guarantor	Subsidiary Issuer	Non- guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Operating revenues:					
Gas transportation	\$ -	\$ -	\$ 845.6	\$ (50.7)	\$ 794.9
Parking and lending	-	-	41.0	(6.1)	34.9
Gas storage	-	-	57.9	(0.3)	57.6
Other	-	-	21.8	-	21.8
Total operating revenues	<u>-</u>	<u>-</u>	<u>966.3</u>	<u>(57.1)</u>	<u>909.2</u>
Operating cost and expenses:					
Fuel and gas transportation	-	-	119.0	(57.1)	61.9
Operation and maintenance	-	-	142.2	-	142.2
Administrative and general	(0.2)	-	122.2	-	122.0
Other operating costs and expenses	0.2	-	288.4	-	288.6
Total operating costs and expenses	<u>-</u>	<u>-</u>	<u>671.8</u>	<u>(57.1)</u>	<u>614.7</u>
Operating income	<u>-</u>	<u>-</u>	<u>294.5</u>	<u>-</u>	<u>294.5</u>
Other deductions (income):					
Interest expense	-	49.9	75.4	-	125.3
Interest expense - affiliates, net	-	55.9	11.8	(60.9)	6.8
Interest income	(42.2)	(12.0)	(6.9)	60.9	(0.2)
Equity in earnings of subsidiaries	(120.5)	(214.3)	-	334.8	-
Miscellaneous other income	-	-	(0.4)	-	(0.4)
Total other deductions (income)	<u>(162.7)</u>	<u>(120.5)</u>	<u>79.9</u>	<u>334.8</u>	<u>131.5</u>
Income before income taxes	162.7	120.5	214.6	(334.8)	163.0
Income taxes	<u>-</u>	<u>-</u>	<u>0.3</u>	<u>-</u>	<u>0.3</u>
Net Income	<u>\$ 162.7</u>	<u>\$ 120.5</u>	<u>\$ 214.3</u>	<u>\$ (334.8)</u>	<u>\$ 162.7</u>

Condensed Consolidating Statements of Cash Flow for the Year Ended December 31, 2011
(in millions)

	Parent Guarantor	Subsidiary Issuer	Non- guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Net Cash Provided by (Used in) Operating Activities	\$ 31.3	\$ 45.0	\$ 529.9	\$ (152.8)	\$ 453.4
Investing Activities:					
Capital expenditures	-	-	(141.7)	-	(141.7)
Proceeds from sale of operating assets	-	-	31.5	-	31.5
Proceeds from insurance reimbursements and other	-	-	9.6	-	9.6
Advances to affiliates, net	227.1	107.8	(288.6)	(46.3)	-
Investment in consolidated subsidiary	(11.6)	-	-	11.6	-
Investment in unconsolidated affiliate	-	(71.2)	-	-	(71.2)
Net Cash Provided by (Used in) Investing Activities	<u>215.5</u>	<u>36.6</u>	<u>(389.2)</u>	<u>(34.7)</u>	<u>(171.8)</u>
Financing Activities:					
Proceeds from long-term debt, net of issuance costs	-	-	437.6	-	437.6
Repayment of borrowings from long- term debt	-	-	(250.0)	-	(250.0)
Payments of premiums on extinguishment of long-term debt	-	-	(21.0)	-	(21.0)
Proceeds from borrowings on revolving credit agreement	-	305.0	280.0	-	585.0
Repayment on borrowings on revolving credit agreement	-	(490.0)	(340.0)	-	(830.0)
Contribution from parent	-	-	11.6	(11.6)	-
Distributions paid	(419.9)	-	(152.8)	152.8	(419.9)
Advances from affiliates, net	-	61.5	(107.8)	46.3	-
Proceeds from sale of common units	170.0	-	-	-	170.0
Capital contribution from general partner	3.6	-	-	-	3.6
Net Cash (Used in) Provided by Financing Activities	<u>(246.3)</u>	<u>(123.5)</u>	<u>(142.4)</u>	<u>187.5</u>	<u>(324.7)</u>
Increase (Decrease) in Cash and Cash Equivalents	0.5	(41.9)	(1.7)	-	(43.1)
Cash and Cash Equivalents at Beginning of Period	<u>-</u>	<u>52.6</u>	<u>2.4</u>	<u>-</u>	<u>55.0</u>
Cash and Cash Equivalents at End of Period	<u>\$ 0.5</u>	<u>\$ 10.7</u>	<u>\$ 0.7</u>	<u>\$ -</u>	<u>\$ 11.9</u>

Condensed Consolidating Statements of Cash Flow for the Year Ended December 31, 2010
(in millions)

	Parent Guarantor	Subsidiary Issuer	Non- guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Net Cash Provided by (Used In)					
Operating Activities	\$ 232.7	\$ (107.6)	\$ 535.8	\$ (196.2)	\$ 464.7
Investing Activities:					
Capital expenditures	-	-	(227.3)	-	(227.3)
Proceeds from sale of operating assets	-	-	30.9	-	30.9
Advances to affiliates, net	176.4	141.8	(196.0)	(122.2)	-
Net Cash Provided by (Used in) Investing Activities	176.4	141.8	(392.4)	(122.2)	(196.4)
Financing Activities:					
Proceeds from borrowings on revolving credit agreement	-	175.0	-	-	175.0
Repayment on borrowings on revolving credit agreement	-	(25.0)	-	-	(25.0)
Payments on note payable	(0.3)	-	-	-	(0.3)
Payments associated with registration rights agreement	(10.7)	-	-	-	(10.7)
Distributions paid	(398.1)	(196.8)	-	196.8	(398.1)
Advances from affiliates, net	-	19.6	(141.8)	122.2	-
Capital contribution from general partner	-	-	0.6	(0.6)	-
Net Cash (Used in) Provided by Financing Activities	(409.1)	(27.2)	(141.2)	318.4	(259.1)
Increase in Cash and Cash Equivalents	-	7.0	2.2	-	9.2
Cash and Cash Equivalents at Beginning of Period	-	45.6	0.2	-	45.8
Cash and Cash Equivalents at End of Period	\$ -	\$ 52.6	\$ 2.4	\$ -	\$ 55.0

Condensed Consolidating Statements of Cash Flow for the Year Ended December 31, 2009
(in millions)

	Parent Guarantor	Subsidiary Issuer	Non- guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Net Cash Provided by (Used In)					
Operating Activities	<u>\$ 165.0</u>	<u>\$ (85.0)</u>	<u>\$ 443.0</u>	<u>\$ (122.5)</u>	<u>\$ 400.5</u>
Investing Activities:					
Capital expenditures	-	-	(846.8)	-	(846.8)
Advances to affiliates, net	(376.2)	(250.6)	311.3	315.5	-
Distribution from consolidated subsidiary	240.0	-	-	(240.0)	-
Investment in consolidated subsidiary	-	(85.6)	-	85.6	-
Note receivable – affiliate	-	153.2	-	(153.2)	-
Sales of short-term investments	-	175.0	-	-	175.0
Net Cash (Used in) Provided by Investing Activities	<u>(136.2)</u>	<u>(8.0)</u>	<u>(535.5)</u>	<u>7.9</u>	<u>(671.8)</u>
Financing Activities:					
Proceeds from long-term debt, net of issuance costs	-	346.7	-	-	346.7
Proceeds from borrowings on revolving credit agreement	-	250.0	161.5	-	411.5
Repayment of borrowings on revolving credit agreement	-	(400.0)	(250.0)	-	(650.0)
Payments on notes payable	(1.3)	-	-	-	(1.3)
Proceeds from long-term debt – affiliate	-	200.0	-	-	200.0
Repayment of long-term debt – affiliate	-	(100.0)	(153.2)	153.2	(100.0)
Contribution from parent	-	-	85.6	(85.6)	-
Distributions paid	(360.6)	(360.6)	-	360.6	(360.6)
Advances from affiliates, net	-	64.9	248.7	(313.6)	-
Proceeds from sale of common units	326.3	-	-	-	326.3
Capital contribution from general partner	6.8	-	-	-	6.8
Net Cash (Used in) Provided by Financing Activities	<u>(28.8)</u>	<u>1.0</u>	<u>92.6</u>	<u>114.6</u>	<u>179.4</u>
(Decrease) Increase in Cash and Cash Equivalents	-	(92.0)	0.1	-	(91.9)
Cash and Cash Equivalents at Beginning of Period	<u>-</u>	<u>137.6</u>	<u>0.1</u>	<u>-</u>	<u>137.7</u>
Cash and Cash Equivalents at End of Period	<u>\$ -</u>	<u>\$ 45.6</u>	<u>\$ 0.2</u>	<u>\$ -</u>	<u>\$ 45.8</u>

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Commission. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2011 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2011, that have materially affected or that are reasonably likely to materially affect our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting for us. Our internal control system was designed to provide reasonable assurance regarding the preparation and fair presentation of our published financial statements.

There are inherent limitations to the effectiveness of any control system, however well designed, including the possibility of human error and the possible circumvention or overriding of controls. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Management must make judgments with respect to the relative cost and expected benefits of any specific control measure. The design of a control system also is based in part upon assumptions and judgments made by management about the likelihood of future events, and there can be no assurance that a control will be effective under all potential future conditions. As a result, even an effective system of internal control over financial reporting can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*. Based on this assessment, our management believes that, as of December 31, 2011, our internal control over financial reporting was effective. Deloitte & Touche LLP, the independent registered public accounting firm that audited our financial statements included in Item 8 of this Report, has issued a report on our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Boardwalk GP, LLC
and the Partners of Boardwalk Pipeline Partners, LP

We have audited the internal control over financial reporting of Boardwalk Pipeline Partners, LP and subsidiaries (the “Partnership”) as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership’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 the Partnership'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, Boardwalk Pipeline Partners, LP and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2011, of the Partnership and our report dated February 21, 2012 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP
Houston, Texas
February 21, 2012

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Boardwalk Pipeline Partners, LP

Boardwalk GP manages our operations and activities on our behalf. The operations of Boardwalk GP are managed by its general partner, Boardwalk GP, LLC (BGL). We sometimes refer to Boardwalk GP and BGL collectively as “our general partner.” Our general partner is not elected by unitholders and is not subject to re-election on a regular basis in the future. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to our unitholders. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Whenever possible, our general partner intends to cause us to incur indebtedness or other obligations that are nonrecourse to it.

Whenever our general partner makes a determination or takes or declines to take an action in its individual, rather than representative, capacity, it is entitled to make such determination or to take or decline to take such other action free of any fiduciary duty or obligation to any limited partner and is not required to act in good faith or pursuant to any other standard imposed by our partnership agreement or under any law. Examples include the exercise of its limited call rights on our units, as provided in our partnership agreement, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of the Partnership, all of which are described in our partnership agreement. Actions of our general partner made in its individual capacity will be made by BPHC, the sole member of BGL, rather than by our Board.

BGL has a board of directors that oversees our management, operations and activities. We refer to the board of directors of BGL, the members of which are appointed by BPHC, as our Board. BPHC does not apply a formal diversity policy or set of guidelines in selecting and appointing directors that comprise the Board. However, when appointing new directors, BPHC does consider each individual director’s qualifications, skills, business experience and capacity to serve as a director, as described below for each director, and the diversity of these attributes for the Board as a whole.

Directors and Executive Officers

The following table shows information for the directors and executive officers of BGL:

<u>Name</u>	<u>Age</u>	<u>Position</u>
Stanley C. Horton	62	Chief Executive Officer, President and Director
Jamie L. Buskill	47	Chief Financial Officer, Senior Vice President and Treasurer
Brian A. Cody	54	Senior Vice President, Asset Management
Michael E. McMahon	56	Senior Vice President, General Counsel and Secretary
Kenneth I. Siegel	54	Director, Chairman of the Board
Arthur L. Rebell	71	Director
William R. Cordes	63	Director
Thomas E. Hyland	66	Director
Mark L. Shapiro	67	Director
Andrew H. Tisch	62	Director

All directors have served since our initial public offering in 2005 except for Messrs. Horton, Siegel and Cordes who were elected to the Board in 2011, 2009 and 2006, respectively. All directors serve until replaced or upon their voluntary resignation.

Stanley C. Horton—Mr. Horton has been the President and Chief Executive Officer (CEO) of BGL since May 2011. Prior thereto he was an independent energy consultant providing consulting services to clients in both Europe and the United States. From 2005 to 2008, Mr. Horton served as President and Chief Operating Officer of Cheniere Energy, Inc. From 2003 to 2005, he served as President and Chief Operating Officer of subsidiaries of Southern

Union, including Panhandle Energy and CrossCountry Energy Services LLC. From 2001 to 2003, Mr. Horton served as Chairman and Chief Executive Officer of Enron Global Services and, from 1997 to 2001, he served as Chief Executive Officer of Enron Transportation Services Company. In December 2001, Enron Corporation and various of its affiliates, including Enron Transportation Services Company, filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York. Mr. Horton was chairman and chief executive officer of EOTT Energy Corp., the general partner of EOTT Energy Partners, L.P., prior to the bankruptcy reorganization filing of EOTT Energy Partners, L.P. in October 2002 under Chapter 11 of the U.S. Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of Texas, Corpus Christi Division. He has chaired the Gas Industry Standards Board, the Interstate Natural Gas Association of America and the Natural Gas Council. Mr. Horton also served on the Board of Directors for SemGroup Corporation from November 2009 until his resignation effective May 2, 2011. Mr. Horton was selected to serve as a director due to his extensive experience in the natural gas industry and his position with the Registrant. He brings substantial operational experience gained from his executive-level leadership history and the perspective of a former chief executive officer.

Jamie L. Buskill—Mr. Buskill has been the Chief Financial Officer and Treasurer of BGL since its inception in 2005 and served in the same capacity for the predecessor of BGL since May 2003. He has served in various management roles for Texas Gas since 1986. Mr. Buskill is a member of the Southern Gas Association Accounting and Finance Committee and serves on the board of various charitable organizations.

Brian A. Cody—Mr. Cody has been the Senior Vice President, Asset Management of BGL since August 2011. Prior thereto, Mr. Cody had been the Chief Operating Officer of BGL since 2009 and Chief Commercial Officer of BGL from 2007 to 2009. He has also served in various management roles for Gulf South including: Vice President of Business Development from 2006 to 2007, Chief Financial Officer from 2005 to 2006, Vice President of Long-Term Marketing from 2003 to 2005 and Controller from 2000 to 2003. He has been employed by Gulf South or its predecessors since 1987 and is a Certified Public Accountant.

Michael E. McMahon—Mr. McMahon has been the Senior Vice President, General Counsel and Secretary of BGL since February 2007. Prior thereto he served as Senior Vice President and General Counsel of Gulf South since 2001. Mr. McMahon has been employed by Gulf South or its predecessors since 1989. Mr. McMahon also serves on the legal committee of the Interstate Natural Gas Association of America.

Kenneth I. Siegel—Mr. Siegel has been employed as a Senior Vice President of Loews since June 2009. From 2008 to 2009 he was employed as a senior investment banker at Barclay's Capital and from September 2000 to 2008 he was employed in a similar capacity at Lehman Brothers. Mr. Siegel was selected to serve as a director on our Board due to his valuable financial expertise, including extensive experience with capital markets transactions, knowledge of the energy industry and his familiarity with the Partnership due to his role in providing investment banking advice to the Partnership during his prior employment at Barclay's Capital and Lehman Brothers.

Arthur L. Rebell—Mr. Rebell was a Senior Vice President of Loews from 1998 until his retirement in June 2010. Mr. Rebell was selected to serve as a director on our Board due to his judgment in assessing business strategies taking into account any accompanying risks, his knowledge of finance, mergers and acquisitions and the energy industry and his familiarity with the Partnership due to his role as a member of the Loews team responsible for the acquisitions of Gulf South and Texas Gas and the formation of the Partnership.

William R. Cordes—Mr. Cordes retired as President of Northern Border Pipeline Company in April 2007 after serving as President from October 2000 to April 2007. He also served as Chief Executive Officer of Northern Border Partners, LP from October 2000 to April 2006. Prior to that, he served as President of Northern Natural Gas Company from 1993 to 2000 and President of Transwestern Pipeline Company from 1996 to 2000. Mr. Cordes has more than 35 years of experience working in the natural gas industry. Mr. Cordes is also a member of the board of Kayne Anderson Energy Development Company and Kayne Anderson Midstream Energy Fund, Inc. Mr. Cordes brings to the Board significant pipeline industry experience as well as his extensive business and management expertise from his background as chief executive officer and president of several public companies.

Thomas E. Hyland—Mr. Hyland was a partner in the global accounting firm of PricewaterhouseCoopers, LLP from 1980 until his retirement in July 2005. Mr. Hyland was selected to serve as a director on our Board due to his

extensive background in public accounting and auditing, which also qualifies him as an “audit committee financial expert” under SEC guidelines.

Mark L. Shapiro—Mr. Shapiro has been a private investor since 1998. From July 1997 through August 1998, Mr. Shapiro was a Senior Consultant to the Export-Import Bank of the United States. Prior to that position, he was a Managing Director in the investment banking firm of Schroder & Co. Inc. Mr. Shapiro also serves as a director for W.R. Berkley Corporation. Mr. Shapiro was selected to serve as a director on our Board due to his extensive knowledge and experience in corporate finance, acquisitions and financial matters from his career in investment banking.

Andrew H. Tisch—Mr. Tisch has been Co-Chairman of the Board of Directors of Loews since January 2006. He is also Chairman of the Executive Committee and a member of the Office of the President of Loews and has been a director of Loews since 1985. Mr. Tisch also serves as a director of CNA Financial Corporation, a subsidiary of Loews, and is Chairman of the Board of K12 Inc. Mr. Tisch’s qualifications to sit on our Board of Directors include his extensive experience on the board of our parent company, his extensive leadership skills and keen business and financial judgment, as well as his role in forming the Partnership.

Our Independent Directors

Our Board has determined that Thomas E. Hyland, Mark L. Shapiro and William R. Cordes are independent directors under the listing standards of the New York Stock Exchange (NYSE). Our Board considered all relevant facts and circumstances and applied the independence guidelines described below in determining that none of these directors has any material relationship with us, our management, our general partner or its affiliates or our subsidiaries.

Our Board has established guidelines to assist it in determining director independence. Under these guidelines, a director would not be considered independent if any of the following relationships exists:

- (i) during the past three years the director has been an employee, or an immediate family member has been an executive officer, of us;
- (ii) the director or an immediate family member received, during any twelve month period within the past three years, more than \$120,000 in direct compensation from us, excluding director and committee fees, pension payments and certain forms of deferred compensation;
- (iii) the director is a current partner or employee or an immediate family member is a current partner of a firm that is our internal or external auditor, or an immediate family member is a current employee of such a firm and personally works on our audit, or, within the last three years, the director or an immediate family member was a partner employee of such a firm and personally worked on our audit within that time;
- (iv) the director or an immediate family member has at any time during the past three years been employed as an executive officer of another company where any of our present executive officers at the same time serves or served on that company’s compensation committee; or
- (v) the director is a current employee, or an immediate family member is a current executive officer, of a company that has made payments to, or received payments from, us for property or services in an amount which, in any of the last three years, exceeds the greater of \$1.0 million, or 2% of the other company’s consolidated gross revenues.

Our Board has appointed an Audit Committee comprised solely of independent directors. The NYSE does not require a listed limited partnership, or a listed company that is majority-owned by another listed company, such as us, to have a majority of independent directors on its board of directors or to maintain a compensation or nominating/corporate governance committee. In reliance on these exemptions, our Board is not comprised of a majority of independent directors, and we do not maintain a compensation or nominating/corporate governance committee.

Audit Committee

Our Board's Audit Committee presently consists of Thomas E. Hyland, Chairman, Mark L. Shapiro and William R. Cordes, each of whom is an independent director and satisfies the additional independence and other requirements for Audit Committee members provided for in the listing standards of the NYSE. The Board of Directors has determined that Mr. Hyland qualifies as an "audit committee financial expert" under Securities and Exchange Commission (SEC) rules.

The primary function of the Audit Committee is to assist our Board in fulfilling its responsibility to oversee management's conduct of our financial reporting process, including review of our financial reports and other financial information, our system of internal accounting controls, our compliance with legal and regulatory requirements, the qualifications and independence of our independent registered public accounting firm (independent auditors) and the performance of our internal audit function and independent auditors. The Audit Committee has sole authority to appoint, retain, compensate, evaluate and terminate our independent auditors and to approve all engagement fees and terms for our independent auditors.

Conflicts Committee

Under our partnership agreement, our Board must have a Conflicts Committee consisting of two or more independent directors. Our Conflicts Committee presently consists of Mark L. Shapiro, Chairman, Thomas E. Hyland and William R. Cordes. The primary function of the Conflicts Committee is to determine if the resolution of any conflict of interest with our general partner or its affiliates is fair and reasonable. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable, approved by all of the partners and not a breach by our general partner of any duties it may owe to our unitholders.

Executive Sessions of Non-Management Directors

Our Board's non-management directors, from time to time as such directors deem necessary or appropriate, meet in executive sessions without management participation. The Chairman of the Audit Committee and the Chairman of the Conflicts Committee alternate serving as the presiding director at these meetings.

Governance Structure and Risk Management

Our principal executive officer and Board chairman positions are held by separate individuals. We have taken this position to achieve an appropriate balance with regard to oversight of company and unitholder interests, Board member independence, power and guidance for the principal executive officer regarding business strategy, opportunities and risks.

Our Board is engaged in the oversight of risk through regular updates from Mr. Horton, in his role as our CEO, and other members of our management team, regarding those risks confronting us, the actions and strategies necessary to mitigate those risks and the status and effectiveness of those actions and strategies. The updates are provided at quarterly Board and Audit Committee meetings as well as through more frequent meetings that include the Board Chairman, other members of our Board, the CEO and members of our management team. The Board provides insight into the issues, based on the experience of its members, and provides constructive challenges to management's assumptions and assertions.

Corporate Governance Guidelines and Code of Business Conduct and Ethics

Our Board has adopted Corporate Governance Guidelines to guide it in its operation and a Code of Business Conduct and Ethics applicable to all of the officers and directors of BGL, including the principal executive officer, principal financial officer, principal accounting officer, and all of the directors, officers and employees of our subsidiaries. The Corporate Governance Guidelines and Code of Business Conduct and Ethics can be found within the "Governance" section of our website. We intend to post changes to or waivers of this Code for BGL's principal executive officer, principal financial officer and principal accounting officer on our website.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16 of the Exchange Act requires our directors and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of ownership and reports of changes in ownership with the SEC. Such persons are required by SEC regulation to furnish us with copies of all Section 16(a) forms they file. Based solely on our review of the copies of such forms furnished to us and written representations from our executive officers and directors, we believe that all Section 16(a) filing requirements were met during 2011, in a timely manner.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Executive Summary

The objective of our executive compensation program is to attract and retain highly qualified executive officers and motivate them to provide a high level of performance for our Partnership and our unitholders both in the short and long term, including maintaining current levels of unitholder distributions and taking prudent steps to grow unitholder distributions. To meet this objective, we have established a compensation policy for our executive officers which offers elements of base salary, cash incentives, equity-based incentives and retirement and other benefits. Our strategy is to combine these elements at levels that provide our Named Executive Officers (as defined below) compensation that is competitive with that offered at similar companies in the energy industry, with particular emphasis on rewarding for performance by offering short and long-term incentive-based compensation. We consider a number of factors in making our determinations of executive compensation, including compensation paid in prior years, whether financial, operating and growth project progress objectives were achieved and the individual contributions of each executive to our overall business success for the year. As described below, we have periodically used and may use in the future executive compensation surveys as general guidelines for setting certain components of compensation.

In the development of our executive compensation programs, particularly with regard to our equity-based compensation plans, we have considered the compensation programs of various companies engaged in similar businesses with similar corporate structures to obtain a general understanding of compensation practices and industry trends. We have also considered the historical compensation policies and practices of our operating subsidiaries and, as discussed below under *Risk Assessment*, whether our compensation policies and practices could possibly introduce material risks to our business. In addition, in light of our structure as a publicly traded partnership, we have considered the applicable tax and accounting impacts of executive compensation, including the tax implications of providing equity-based compensation to our employees, all of whom are employed by our operating subsidiaries.

In 2011, approximately 76% of the total direct compensation awarded to our Named Executive Officers was based on incentive-based compensation elements, the majority of which was comprised of annual cash incentive awards. The 2011 annual cash incentive amounts were determined based on the performance of our Partnership and the individual performance of each of the Named Executive Officers. With respect to Partnership performance, our 2011 results, which significantly impacted the Board's compensation decisions, included the following:

- We operated pipeline systems safely, although we had a fire at our Carthage compressor station early in the year;
- We successfully closed a transaction to own and operate a pipeline in the Marcellus Shale area and formed a joint venture with BPHC which acquired Petal Gas Storage, L.L.C., Hattiesburg Gas Storage Company and related entities;
- We implemented several cost reduction programs, including monetizing and reducing carrying costs for a significant portion of our materials and supplies;
- We increased revenues from power generators and improved our competitive position in capturing additional power generation load; and
- We increased our cash distribution each quarter, albeit at a slower pace than we expected. Our distributable cash of \$390.9 million for the 2011 period was lower than expected, primarily driven by the effects of difficult market conditions impacting parking and lending and storage revenues and throughput volumes, as well as higher than expected expenditures for maintenance projects.

Based on these results and the leadership, performance and efforts of each of the Named Executive Officers toward the achievement of these results, the Board of Directors (Board) awarded to the Named Executive Officers individual annual cash incentive compensation amounts that, on a combined basis, were slightly less than the target amounts set earlier in 2011.

In May 2011, Mr. Stanley C. Horton was hired and appointed as President, Chief Executive Officer and a director of BGL, replacing Mr. Rolf A. Gafvert as President and Chief Executive Officer. As discussed elsewhere in this Report, our Board does not have a Compensation Committee. Therefore, the compensation for Mr. Horton, Mr. Jamie L. Buskill, our Chief Financial Officer (CFO) (principal financial officer) and our two other executive officers, Mr. Brian A. Cody and Mr. Michael E. McMahon (collectively, our Named Executive Officers), is reviewed with and is subject to the approval of our entire Board, with Mr. Horton not participating in those Board discussions with respect to his own compensation.

Compensation Philosophy

Our compensation philosophy is to reward our Named Executive Officers for achieving Partnership and individual performance objectives, align the interests of the Named Executive Officers with unitholders interests and provide competitive pay to attract and retain top talent.

Compensation Program Objectives

The objectives of our compensation program are to:

- Create a strong link between pay and performance (both Partnership and individual performance);
- Motivate the Named Executive Officers to achieve both short and long-term Partnership goals;
- Align interests of Named Executive Officers with the interests of unitholders;
- Encourage prudent business behavior and minimize inappropriate risk taking; and
- Attract, motivate and retain highly qualified Named Executive Officers with market-competitive compensation.

Compensation Program Elements

The following are the principal components of compensation for each of our Named Executive Officers:

<u>Compensation Element</u>	<u>Objectives</u>	<u>Design Elements</u>
Base Salary	<ul style="list-style-type: none"> • Attract and retain executives by providing guaranteed compensation comparable with similar positions in the industry. 	<ul style="list-style-type: none"> • Salary levels are reviewed annually and may be adjusted based both on individual performance and market competitiveness of total direct compensation (which is the sum of base salary, short-term incentive awards and long-term incentive awards).
Short-Term Incentive Award	<ul style="list-style-type: none"> • Drive annual business performance by rewarding achievement of Partnership objectives. • Drive individual performance by including an individual performance component. • Align with unitholder interests by setting Partnership objectives that will yield strong financial and operational results. • Attract talent by providing competitive target cash incentives. • Reinforce corporate values of safety and compliance as Partnership objectives. 	<ul style="list-style-type: none"> • Awards are comprised of annual cash incentive awards (STI Awards) under our Short-Term Incentive Plan (STIP). • Payout of award can range from 0% to 200% of target based both on Partnership and individual performance, with equal weighting on both. • Target levels are reviewed annually and may be adjusted based on market competitiveness of total direct compensation.

Long-Term Incentive Award	<ul style="list-style-type: none"> • Drive long-term business performance by aligning reward with unit price, appreciation in unit price and distributions. • Drive individual performance by setting grant levels based on individual performance. • Attract and retain talent and motivate top performance and provide opportunity to share in long-term success of the Partnership. • Minimize inappropriate risk-taking by providing right mix of award types.
Benefits	<ul style="list-style-type: none"> • Awards are made up of phantom common units (Phantom Common Units) under our Long-Term Incentive Plan (LTIP) and unit appreciation rights (UARs) under our Unit Appreciation Rights and Cash Bonus Plan (UAR and Cash Bonus Plan). • Vesting at the end of three years achieves retention objectives. • Phantom common units encourage retention and facilitate alignment with unitholders interests. • Unit appreciation rights encourage participants to increase the unit price and increase distributions, and provide the greater leverage or upside opportunity. • Mix of award types is reviewed annually; currently a smaller percentage of the awards are provided as UARs. • Award levels are reviewed annually and are based on individual performance and market competitiveness of total direct compensation.
Benefits	<ul style="list-style-type: none"> • Attract and retain executives by providing market competitive benefits. • Reviewed annually to ensure competitiveness.

Market Analysis

When determining the appropriate amounts of individual compensation components, the Board considers a number of factors, including the individual officer's skills, experience and responsibilities, the amounts of current and prior compensation as well as the appropriate amounts necessary to further our retention efforts. We do not determine compensation by benchmarking, or targeting our compensation to fall within a specific percentile of compensation as reported in compensation surveys.

However, as described above, a key objective of our Compensation program is to maintain market competitiveness in order to attract and retain executives with the ability and experience necessary to provide leadership and to deliver strong performance to our unitholders. Therefore, from time to time, we may review market compensation data to assess the reasonableness of our compensation practices.

With respect to our 2011 compensation decisions, we used the 2011 Towers Watson U.S. Compensation Data Bank Energy Services Executive Database ("Towers Database") and the 2011 US Mercer Total Compensation Survey for the Energy Sector (the "Mercer Survey") to conduct a market-based review of total direct compensation, which we define as the sum of base salary, short-term incentives and long-term based incentives. The compensation survey data we reviewed was from approximately 90 companies that are engaged in various segments of the energy industry, with revenues ranging from \$1 billion to \$3 billion.

We determined a median market total direct compensation amount for each officer position, which was equal to (i) average median base salary (representing the average of the Towers Database and the Mercer Survey median base salary amounts), plus (ii) median short-term annual cash incentive awards, plus (iii) median long-term incentive awards. Our general objective was to assess each officer's total direct compensation for reasonableness in

relation to the median amount for similarly situated officers. We did not set specific target percentiles for either total direct compensation or the individual compensation components.

When making compensation decisions, the Board considers all information available, including the factors listed above, with the final amounts of compensation to be ultimately determined at the discretion of the Board. This process allows us to achieve our primary objective of maintaining competitive compensation to ensure retention and rewarding the achievement of company objectives to align with unitholders interest.

The following discussion addresses each of the individual components of compensation for our Named Executive Officers.

Base Salary

We provide our Named Executive Officers with an annual base salary to compensate them for services rendered during the year. Our goal is to set base salaries for our Named Executive Officers at levels that make total direct compensation competitive with comparable companies for the skills, experience and requirements of similar positions in order to attract and retain top talent.

The base salaries of our Named Executive Officers were not changed during 2011. This determination was made as a result of reviewing the market-competitiveness of total direct compensation, and taking into account base salary changes that were made in 2010 which increased base salaries for our Named Executive Officers by amounts ranging from 8% to 31%. As discussed under *Executive Summary* and in Item 10 of this Report, Mr. Horton was hired and assumed the title of President and Chief Executive Officer in May 2011. Mr. Horton's base salary, as a component of his total direct compensation, was determined through negotiations with him during the hiring process. The base salary and other elements of Mr. Horton's compensation are included in a one-year employment agreement with him which is discussed further under *Narrative Disclosure to Summary Compensation Table and Grant of Plan Based Awards Table*.

Incentive Compensation

Our incentive compensation program is comprised of two components – annual cash incentive awards under our STIP and long-term, equity-based awards under our LTIP and UAR and Cash Bonus Plan. Our goal is to set incentive target awards at levels that make total direct compensation competitive with comparable companies for the skills, experience and requirements of similar positions in order to attract and retain top talent. The incentive target awards can differ from actual awards as a result of Partnership and/or individual performance, but the actual payout of any award is determined at the sole discretion of the Board.

In determining the amount of any incentive awards, the Board considers factors that include its view of our financial and operational performance for the most recently completed fiscal year, the performance of the individual, the responsibilities of the individual's position and the individual's contribution to our Partnership. Except with regard to STI Awards made under the STIP, there is no specific weight assigned to any factor. Instead, the Board considers and balances the various performance objectives as it deems appropriate.

STI Awards. An STI Award is an annual incentive cash award under our STIP, the payout of which is based on the Board's subjective analysis of our performance and the performance of our Named Executive Officers during the year. At the beginning of the year, each Named Executive Officer is assigned a target amount, which is established as a percentage of the officer's base salary. The plan provides that payouts under the STIP can range from zero to 200% of the target amount, with 50% of the payout determined after taking into account our Partnership's performance and 50% based on individual performance. The target and maximum potential payouts under the STIP as well as the allocation between Partnership and individual performance were determined at the discretion of the Board. In determining the target amount of the STI Awards, the Board considered (i) the value of each officer's prior STI Awards, and (ii) the potential value of these awards on the total direct compensation for each officer. Similarly, in negotiating the target amount for Mr. Horton, the Board considered the potential value of the award on the total direct compensation being negotiated. The following are the target potential payout amounts that were established in 2011 for our Named Executive Officers:

Name	Base Salary	2011 STI Target %	Total 2011 Potential Cash Compensation Assuming Target
			STI Payout
Stanley C. Horton	\$400,000 ^(a)	100%	\$400,000 ^(a)
Jamie L. Buskill	\$325,000	100%	\$325,000
Brian A. Cody	\$300,000	100%	\$300,000
Rolf A. Gafvert	\$425,000	100%	\$425,000
Michael E. McMahon	\$265,000	100%	\$265,000

(a) Represents a prorated portion for 2011 of annual base salary and STI target payout of \$600,000.

At the end of each year, when determining whether to pay an STI Award, the Board considers recommendations made by the CEO which are based on his subjective evaluation of whether, and to what extent, our Partnership met its performance goals during the year. He also makes recommendations based on his subjective assessment of the individual performance of each of the other Named Executive Officers. Any STI Award paid to the CEO is determined by the Board based upon a similar review without input from the CEO.

Our partnership performance goals are based on objectives that we believe reflect a well-rounded view of our performance. However, these goals are not tied to any specific targets and our achievement of these goals is ultimately determined by the Board in its sole discretion. For 2011, the following general objectives, which we refer to as Partnership Performance Goals, were established by the CEO and approved by the Board:

- Operate without a significant safety incident and provide reliable firm transportation and storage services;
- Deliver strong financial performance as measured by key financial metrics including distributable cash, EBITDA and return on investment;
- Successfully close on expansion and/or acquisition opportunities meeting an acceptable risk return profile;
- Utilize Boardwalk's assets to improve operating efficiencies;
- Successfully capture power generation load as power providers convert legacy facilities; and
- Pursue opportunities to increase system utilization by expanding system and service optionality in order to capture market share where assets are being underutilized.

As discussed under *Executive Summary*, in light of the achievements of our Partnership in 2011, the Board determined that we met a significant portion of our Partnership Performance Goals, which resulted in 89% of the partnership performance portion of each STI Award being paid.

The Board also subjectively considered the contributions of our Named Executive Officers, including the individual leadership, performance and efforts of each officer with respect to our achievement of these goals. The following is a discussion of the material factors that were considered by the Board in determining what percentage of the annual incentive award would be paid based on individual performance:

Stanley C. Horton: In assessing Mr. Horton's individual performance, the Board considered the leadership that he provided for the senior management team and employee group, as well as the implementation of the strategic direction he communicated to the employee group in terms of growth, financial performance, diversification, customer service, operational excellence and ethics and integrity. Under Mr. Horton's leadership, the Partnership was able to begin to execute in terms of the strategic direction by closing a transaction to own and operate a pipeline in the Marcellus Shale area and forming a joint venture with BPHC which acquired Petal Gas Storage, L.L.C., Hattiesburg Gas Storage Company and

related entities; implementing several cost reduction programs; increasing revenues from power generators and improving the Partnership's competitive position in capturing additional power generation load; and continuing to increase partner distributions each quarter during 2011.

Jamie L. Buskill: In assessing Mr. Buskill's performance, the Board considered his continued leadership of the finance and accounting organization, including developing and maintaining effective communication with the investment community, ensuring the proper capitalization of the Partnership to sustain a secure investment grade debt rating, providing fiduciary oversight by ensuring effective controls, procedures and risk management practices are in place and effective cash management to provide sufficient liquidity for executing the Partnership's operating plans.

Brian A. Cody: In assessing Mr. Cody's performance, the Board considered his leadership of the operations and engineering organizations, negotiation and positive resolution of certain third-party claim matters, streamlining of project estimation and design and timely delivery on projects and key initiatives for reliability, operational performance and compliance.

Michael E. McMahon: In assessing Mr. McMahon's performance, the Board considered his leadership of the legal and regulatory organizations, including execution of a regulatory strategy to promote changes to the interstate pipeline tariffs to meet current and future market conditions and for the successful transfer of certain assets to Boardwalk Field Services, as well as successful negotiation and positive resolution of certain third-party claim matters.

Rolf A. Gafvert: In assessing Mr. Gafvert's performance, the Board considered his performance while he was CEO and President, and afterwards, his role as advisor to Mr. Horton and his help with Mr. Horton's transition into the President and CEO positions.

In light of these considerations, the Board approved the following payout of STI Awards for each Named Executive Officer:

Name	STI Award \$	2011 Incentive
		Payout as % of Base Salary
Stanley C. Horton	\$600,000	150%
Jamie L. Buskill	\$305,000	94%
Brian A. Cody	\$220,000	73%
Michael E. McMahon	\$275,000	104%
Rolf A. Gafvert	\$250,000	59%

Each of the STI awards above was determined as follows: 50% of the award was based on a Partnership performance of 89% of target and 50% of the award was based on individual performance, as determined at the discretion of the Board.

Long-Term Incentive Awards – Phantom Common Units and UARs. We grant equity-based compensation awards to our Named Executive Officers under our LTIP and our UAR and Cash Bonus Plan on an annual basis. However, due to our structure as a limited partnership and certain tax matters associated with employee benefit plans, we currently limit the type of equity-based awards that we grant to Phantom Common Units under our LTIP and UARs under our UAR and Cash Bonus Plan, rather than actual common units. With a typical three-year vesting condition and the opportunity for long-term unit appreciation, these awards help us achieve our objectives of retention, growing unit value and cash distributions, linking our executive pay to Partnership performance and aligning the interests of our Named Executive Officers with those of unitholders.

Upon satisfaction of the time-based vesting criteria specified in the grant, a Phantom Common Unit converts into the right to receive the value of a common unit in cash or, at the option of the Board, a common unit, plus an amount in cash equal to the accumulated amount of cash distributions made during the vesting period with respect to a common unit. Upon satisfaction of the time-based vesting criteria

specified in the grant, a UAR entitles the grantee to a payment in cash equal to the excess, if any, of the price of a common unit on the vesting date over the exercise price of the UAR (reduced by the accumulated amount of cash distributions made over the vesting period with respect to a common unit).

December 2011 Awards. In December 2011, we implemented certain changes to the long-term component of our compensation program applicable to selected employees including our Named Executive Officers, including not making grants of long-term cash bonuses, granting UARs without an applicable dollar cap amount per UAR (UAR Cap) and changing the mix of the type of long-term equity incentive awards granted. As a result of those changes, the Board awarded approximately 75% of the value of our long-term incentive compensation in the form of Phantom Common Units and 25% as UARs. We believe that eliminating the long-term bonus awards and the UAR Cap, as well as awarding this mix of Phantom Common Units and UARs achieves an appropriate balance among our objectives described above, and in particular, between our retention efforts and aligning the interests of our executives with those of our unitholders.

In determining the size of the December long-term incentive awards granted to our Named Executive Officers and in assessing the reasonableness of those awards, the Board considered the value of each officer's prior long-term incentive awards, as well as the impact of the value of long-term incentive awards on total direct compensation in relation to the market data from the Towers Database. However, in light of Mr. Gafvert's resignation in 2011 of his position as President and Chief Executive Officer, no long-term incentive awards were granted to him.

Mr. Horton's June 2011 Award. As discussed below, the value and terms of the long-term incentive awards, including the long-term cash bonus award, granted to Mr. Horton upon the commencement of his employment in June 2011 were determined in connection with the negotiation of the terms of his employment agreement, which is further described under *Narrative Disclosure to Summary Compensation Table and Grant of Plan Based Awards Table*.

Employee Benefits

Each Named Executive Officer participates in benefit programs available generally to salaried employees of the operating subsidiary which employs such officer, including health and welfare benefits and a qualified defined contribution 401(k) plan that includes a dollar-for-dollar match on elective deferrals of up to 6% of eligible compensation within Internal Revenue Code (IRC) requirements. Certain Named Executive Officers participate in a defined contribution money purchase plan available to employees of Gulf South and employees of Texas Gas hired on or after November 1, 2006, while one participates in a defined benefit cash balance pension plan available to employees of Texas Gas hired prior to November 1, 2006, and includes a non-qualified restoration plan for amounts earned in excess of IRC limits for qualified retirement plans. One Named Executive Officer is also eligible for retiree medical benefits after reaching age 55 as part of a plan offered to Texas Gas employees hired prior to January 1, 1996.

Equity Ownership Guidelines

As discussed above, our executives would suffer significant negative tax consequences by owning our units directly. As a result, we do not have a policy or any guidelines regarding equity ownership by our management. We therefore seek to align the interests of management with our unitholders by granting Phantom Common Units and UARs and, prior to 2010, grants of Phantom GP Units. Although no additional grants of Phantom GP Units will be made, we believe that previous years' awards that are currently outstanding and unvested also help achieve this objective.

All Other Compensation

There were no material perquisites or personal benefits paid to our Named Executive Officers in 2011.

Employment Agreements

Historically, we have not had employment agreements with our Named Executive Officers. However, in connection with the hiring of Mr. Horton as our new President and Chief Executive Officer, we entered into a one-year employment agreement with him. The Board's principal objectives in entering into the new employment agreement with Mr. Horton were to secure access to his leadership and experience. Mr. Horton's base salary, short-term incentive target award and his long-term incentive awards and the other provisions of the agreement were arrived at through negotiation with Mr. Horton and a review of market data regarding total direct compensation awarded to similarly situated officers at other companies. Any payments that could be made under the agreement in the event of termination of employment correspond to those that would be made under the applicable plans as described below under *Potential Payments Upon Termination or Change of Control*. For a discussion of the additional material terms for Mr. Horton's employment agreement, please see *Narrative Disclosure to Summary Compensation Table and Grant of Plan Based Awards Table — Employment Agreement*.

Risk Assessment

We have reviewed our compensation policies and practices for all employees, including Named Executive Officers, and determined that our compensation programs are not reasonably likely to cause behaviors that would have a material adverse effect on the Partnership. In arriving at this determination, the Board considers potential risks when reviewing and approving both executive level and broad-based compensation programs. We have designed our compensation programs, including our incentive compensation plans, to minimize potential risks while rewarding employees for achieving long-term financial and strategic objectives through prudent business judgment. In particular, the design of our compensation programs provide a balanced mix of cash and equity-based, annual and longer-term incentives, which are discretionary and subject to the Board's evaluation of Partnership performance metrics as well as individual contributions to our performance. Further, awards of incentive compensation are not purely formula driven, and the Board retains full discretion with regard to increasing or decreasing total compensation or any element of total compensation.

Board of Directors Report on Executive Compensation

In fulfilling its responsibilities, our Board has reviewed and discussed the Compensation Discussion and Analysis with our management. Based on this review and discussion, the Board recommended that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

By the members of the Board of Directors:

William R. Cordes
Stanley C. Horton
Thomas E. Hyland
Arthur L. Rebell
Kenneth I. Siegel, Chairman
Mark L. Shapiro
Andrew H. Tisch

Compensation Committee Interlocks and Insider Participation

As discussed above, our Board does not maintain a Compensation Committee. Our entire Board performs the functions of such a committee. None of our directors, except Mr. Horton, have been or are officers or employees of us or our subsidiaries. Mr. Horton participates in deliberations of our Board with regard to executive compensation generally, but does not participate in deliberations or Board actions with respect to his own compensation. None of our Named Executive Officers served as a director or member of a compensation committee of another entity that has or has had an executive officer who served as a member of our Board during 2011, 2010 or 2009.

Executive Compensation

Summary of Executive Compensation

The following table shows a summary of total compensation earned by our Named Executive Officers during 2011, 2010 and 2009:

Summary Compensation Table for 2011								
Name and Principal Position	Year	Salary (1) (\$)	Bonus (2) (\$)	Option Awards (3) (\$)	Stock Awards (3) (\$)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (\$)	All Other Compensation (\$)	Total (10) (\$)
Stanley C. Horton, CEO (beginning May 11)								
	2011	403,848	600,000	523,502	974,992	-	145,884 ⁽⁴⁾	2,648,226
Rolf A. Gafvert, CEO (through May 10)								
	2011	425,000	250,000	-	-	-	32,465 ⁽⁵⁾	707,465
	2010	325,000	500,000	247,706	-	-	35,202	1,107,908
	2009	337,500	450,000	-	-	-	33,842	821,342
Jamie L. Buskill, CFO								
	2011	325,000	305,000	105,190	374,993	111,730 ⁽⁶⁾	17,243 ⁽⁷⁾	1,239,156
	2010	300,000	275,000	137,614	-	103,533	17,085	833,232
	2009	311,538	275,000	-	-	91,527	17,085	695,150
Brian A. Cody, Senior Vice President, Asset Management								
	2011	300,000	220,000	63,114	225,007	-	27,199 ⁽⁸⁾	835,320
	2010	255,000	275,000	137,614	-	-	27,216	694,830
	2009	262,500	300,000	-	-	-	28,118	590,618
Michael E. McMahon, Senior Vice President, General Counsel and Secretary								
	2011	265,000	275,000	73,630	262,490	-	28,248 ⁽⁹⁾	904,368
	2010	240,000	275,000	89,447	-	-	28,298	632,745
	2009	249,231	275,000	-	-	-	26,928	551,159

- (1) The payroll cycle contained one additional pay period in 2009 as compared to 2011 and 2010.
- (2) The amounts shown in this column represent cash STI Awards earned under our STIP for 2011 and 2010 and annual bonus payments earned for 2009.
- (3) The amounts reflected represent the aggregate grant date fair value for grants made during the fiscal year. The "Option Awards" column includes UARs granted under our UAR and Cash Bonus Plan. The "Stock Awards" column includes Phantom Common Units granted under our LTIP. Note 9 in Item 8 of this Report contains information regarding the assumptions we made in determining these values.
- (4) Includes a payment of \$128,464, including a tax gross up, to make up for unvested rights Mr. Horton was required to forfeit in connection with his resignation as a member of the board of directors of SemGroup Corporation, matching contributions under 401(k) plan (\$14,700), imputed life insurance premiums, and preferred parking.
- (5) Includes matching contributions under 401(k) plan (\$14,700), employer contributions to the Gulf South Money Purchase Plan, club memberships, imputed life insurance premiums, and preferred parking.
- (6) Includes the change in qualified retirement plan account balance (\$49,397) and interest and pay credits for the supplemental retirement plan (\$62,333).

- (7) Includes matching contributions under 401(k) plan (\$14,700), imputed life insurance premiums and preferred parking.
- (8) Includes matching contributions under 401(k) plan (\$14,700), employer contributions to the Gulf South Money Purchase Plan, spouse travel, imputed life insurance premiums, preferred parking and travel clubs.
- (9) Includes matching contributions under 401(k) plan (\$14,700), employer contributions to the Gulf South Money Purchase Plan, imputed life insurance premiums, and preferred parking.
- (10) In addition to the compensation reportable herein, in 2011 a Long-Term Cash Bonus was granted to Mr. Horton having a stated amount of \$258,000. In 2010, Long-Term Cash Bonuses were granted to Messrs. Gafvert, Buskill, Cody and McMahon having stated amounts of \$270,000, \$150,000, \$150,000 and \$97,500. The awards will vest and become payable, subject to the terms of the plan and grant agreements on December 16, 2013. See *Compensation Discussion and Analysis and Potential Payments Upon Termination or Change of Control* for more information regarding the terms of the Long-Term Cash Bonus awards.

The following table sets forth the percentage of each Named Executive Officer's total compensation that we paid in the form of salary and bonus:

<u>Named Executive Officer</u>	<u>Year</u>	<u>Percentage of Total Compensation Paid as Salary and Bonus</u>
Stanley C. Horton	2011	38%
Rolf A. Gafvert	2011	95%
	2010	74%
	2009	96%
Jamie L. Buskill	2011	51%
	2010	69%
	2009	84%
Brian A. Cody	2011	62%
	2010	76%
	2009	95%
Michael E. McMahon	2011	60%
	2010	81%
	2009	95%

In 2009, long-term, equity-based awards were not granted to our NEOs. As a result, the percentage of total compensation paid as salary and bonus was higher in 2009 than in 2010.

Grants of Plan-Based Awards

The following table displays information regarding grants made during 2011 to our Named Executive Officers of plan-based awards under our UAR and Cash Bonus Plan and Phantom Common Unit awards under our LTIP:

Grants of Plan-Based Awards for 2011					
Names	Grant Date	All Other Stock Awards: Number of Shares of Stock or Units	All Other Options Awards: Number of Securities Underlying Options	Exercise or Base Price of Option Awards	Grant Date Fair Value of Stock and Option Awards
		(1) (#)	(2) (#)	(3) (\$)	(4) (\$)
Stanley C. Horton	06/30/11	-	71,277	28.93	250,000
	12/14/11	35,714	40,235	27.30	1,248,494
Jamie L. Buskill	12/14/11	13,736	15,475	27.30	480,183
Brian A. Cody	12/14/11	8,242	9,285	27.30	288,121
Michael E. McMahon	12/14/11	9,615	10,832	27.30	336,120

- (1) Represents Phantom Common Units granted under our LTIP. The fair value of each unit was derived based on the closing price of \$27.30 for our common units on the New York Stock Exchange (NYSE) on December 14, 2011. Each such grant includes a tandem grant of Distribution Equivalent Rights (DERs); vests 100% on the third anniversary of the grant date; and will be payable to the grantee in cash, or in common units at the Board's option, upon vesting in an amount equal to the fair market value of the units (as defined in the plan) that vest on the vesting date. The vested amount then credited to the grantee's DER account will be payable in cash.
- (2) Represents UARs granted under our UAR and Cash Bonus Plan. The exercise prices for the UARs granted on December 14, 2011 and June 30, 2011 are equal to the closing price of our common units on the NYSE on those days, or \$27.30 and \$28.93, respectively. The UARs granted on December 14 and June 30 will vest and become payable in cash upon the expiration of restricted periods of 3 years and 2.5 years, respectively, subject to the terms of the plan and grant agreements. The UARs granted to Mr. Horton on June 30 are limited to a UAR Cap of \$12.67.
- (3) Each UAR includes a DER Adjustment, whereby the exercise price is reduced by the amount of any cash distributions made by us with respect to a common unit during the restricted period.
- (4) Note 9 in Item 8 of this Report contains information regarding the grant date fair value of the UARs and Phantom Common Units.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

As discussed under *Overview of Compensation Elements*, in December, 2011 we implemented changes to the long-term component of our compensation program applicable to selected employees including our Named Executive Officers, to be comprised of Phantom Common Units under our LTIP and UARs under the UAR and Cash Bonus Plan. In 2010, the long-term component of our compensation program was comprised of grants of UARs and Long-Term Cash Bonuses under the UAR and Cash Bonus Plan. The long-term compensation awards made on June 30, 2011 to Mr. Horton pursuant to our employment agreement with him were comprised of UARs and a Long-Term Cash Bonus, on similar terms to those granted to the other executives in 2010, because the changes to the long-term component of our compensation program described above had not been made at that point. The terms of Mr. Horton's employment agreement are discussed further below. No changes were made to the terms of any outstanding awards of equity-based compensation made to our Named Executive Officers.

The following provides information regarding the equity-based compensation awards shown in the Summary Compensations table.

Phantom Common Units. Each outstanding Phantom Common Unit includes a tandem grant of Distribution Equivalent Rights (DERs). Each Phantom Common Unit granted in 2011 vests on the third anniversary

date of the grant date, and will be payable to the grantee in cash upon vesting, or in common units at the Board's option, in an amount equal to the fair market value of the units (as defined in the plan) that vest on the vesting date. The vested amount then credited to the grantee's DER account will be payable only in cash.

UARs. After the expiration of a restricted period, each awarded UAR vests and is payable to the holder in cash equal to the amount by which the fair market value (as defined in the plan) of a common unit on such date exceeds the exercise price of the UAR. Each outstanding UAR includes a feature whereby the exercise price is reduced by the amount of any cash distributions made by us with respect to a common unit during the restricted period (DER Adjustment). The amount payable with respect to a UAR awarded prior to December, 2011 is limited to the applicable dollar cap amount per UAR (UAR Cap), although no such UAR Cap applies to awards made in December 2011.

Employment Agreement. We entered into a one-year employment agreement with Mr. Horton dated May 2, 2011, the terms of which cover his compensation package, payments in the event of termination of employment due to death, disability, or other reasons during the term of the agreement and non-solicitation and non-competition assurances. The agreement provides that Mr. Horton will receive an annual base salary of \$600,000 and will be eligible to participate in the STIP, with a target payout of \$400,000 for the remainder of 2011 and \$600,000 for the full year 2012. In June 2011, Mr. Horton was also granted a total of \$860,000 of UARs and Long-Term Cash Bonuses under the UAR and Cash Bonus Plan. Mr. Horton's employment agreement further provides that for the subsequent year his long-term incentive award would be an aggregate of \$1,300,000. Potential payments made under the agreement in the event of termination of employment correspond to those that would be made under the applicable plans as described under *Potential Payments Upon Termination or Change of Control*. Under the agreement, we made a payment of \$128,464, including a tax gross up to Mr. Horton to make up for unvested rights he was required to forfeit in connection with his resignation as a member of the board of directors of SemGroup Corporation. We do not have employment agreements with our other Named Executive Officers.

For more information about the components of compensation reported in the Summary Compensation Table and Grants of Plan-Based Awards, please read the *Compensation Discussion and Analysis*.

Outstanding Equity Awards at Fiscal Year-End

The table displayed below shows the total number of outstanding equity awards in the form of UARs under our UAR and Cash Bonus Plan, Phantom Common Units awarded under our LTIP and Phantom GP Units awarded under our SLTIP and held by our Named Executive Officers at December 31, 2011:

Outstanding Equity Awards at December 31, 2011							
Name	Option/UAR Awards			Stock Awards			
	UARs			Phantom Common Units		Phantom GP Units	
	Number of Securities Underlying Unexercised Options/UARs	Option/UAR Exercise Price (\$)	Option/UAR Expiration Date	Number of Shares or Units That Have Not Vested	Market Value of Shares or Units of Stock That Have Not Vested (6) (\$)	Number of Shares or Units of Stock That Have Not Vested	Market Value of Shares or Units of Stock That Have Not Vested (7) (\$)
Stanley C. Horton	40,235	27.30 (1)	(4)	35,714	988,206	-	-
	71,277	28.93 (2)	(5)				
Rolf A. Gafvert	59,886	30.36 (3)	(5)	-	-	50	2,094,248
Jamie L. Buskill	15,475	27.30 (1)	(4)	13,736	380,075	24	1,005,239
	33,270	30.36 (3)	(5)				
Brian A. Cody	9,285	27.30 (1)	(4)	8,242	228,056	22	921,469
	33,270	30.36 (3)	(5)				
Michael E. McMahon	10,832	27.30 (1)	(4)	9,615	266,047	21	879,584
	21,625	30.36 (3)	(5)				

- (1) The exercise price for each UAR granted in December 2011 is \$27.30, the closing price of our common units on the NYSE on December 14, 2011. Each of these UARs includes a DER Adjustment, which was zero through December 31, 2011. Note 9 in Item 8 of this Report contains more information regarding our UAR and Cash Bonus Plan.
- (2) The exercise price for each UAR granted in June 2011 is \$28.93, the closing price of our common units on the NYSE on June 30, 2011. A UAR cap of \$12.67 was established for each of these UARs, and each of these UARs includes a DER Adjustment which was \$1.0525 through December 31, 2011.
- (3) The exercise price for each UAR granted in 2010 is \$30.36, the closing price of our common units on the NYSE on December 15, 2010. A UAR cap of \$15.76 was established for each of these UARs, and each of these UARs includes a DER Adjustment which was \$2.095 through December 31, 2011.
- (4) These UARs will vest and become payable in cash to each Named Executive Officer upon the expiration of a restricted period, or December 14, 2014.
- (5) These UARs will vest and become payable in cash to each Named Executive Officer upon the expiration of a restricted period, or December 16, 2013.
- (6) The market value reported is based on the NYSE closing market price on December 30, 2011 of \$27.67. The Phantom Common Units will vest on December 14, 2014. No cash distributions were paid on behalf of our common units during the period these Phantom Common Units were outstanding, therefore no amounts were credited to the DERs associated with these awards through December 31, 2011. Note 9 in Item 8 of this Report contains more information regarding our LTIP.
- (7) The market value reported is based on the NYSE closing market price on December 30, 2011 of \$27.67 and the formula contained in the plan. The vesting period of the Phantom GP Units granted to our Named Executive Officers is 4.0 years from the initial date of grant. Note 9 in Item 8 of this Report contains more information regarding our SLTIP.

Option Exercises and Stock Vested

The following table presents information regarding the vesting during 2011 of Phantom Common Units and Phantom GP Units previously granted to our Named Executive Officers.

Option Exercises and Stock Vested for 2011				
Name	Stock Awards			
	Number of LTIP Awards Vesting (#)	Value Received on Vesting (1) (\$)	Number of SLTIP Awards Vesting (#)	Value Received on Vesting (2) (\$)
Rolf A. Gafvert	4,357	144,848	25	1,089,779
Jamie L. Buskill	1,867	62,068	10	435,912
Brian A. Cody	1,867	62,068	15	653,867
Michael E. McMahon	1,245	41,390	12	523,094

- (1) The LTIP awards (Phantom Common Units) vested in December, 2011 and were paid out in a lump sum in January, 2012 in accordance with the plan provisions. At no time were units issued to or owned by the Named Executive Officers.
- (2) The SLTIP awards (Phantom GP Units) vested in February, 2011 and were paid out in a lump sum in April, 2011 in accordance with the plan provisions. At no time were units issued to or owned by the Named Executive Officers.

Pension Benefits

The table displayed below shows the present value of accumulated benefits for our Named Executive Officers. Only employees of our Texas Gas subsidiary hired prior to November 1, 2006, are eligible to receive the pension benefits discussed below. Messrs. Horton, Gafvert, Cody and McMahon are, and during 2011 were employees of our Gulf South subsidiary and are not covered under any Texas Gas benefit plans. Pension benefits include both a qualified defined benefit cash balance plan and a non-qualified defined benefit supplemental cash balance plan (SRP).

Pension Benefits for 2011				
Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit (\$)	Payments During Last Fiscal Year (\$)
Jamie L. Buskill	TGRP	25.3	343,759	-
	SRP	25.3	214,625	-

The Texas Gas Retirement Plan (TGRP) is a qualified defined benefit cash balance plan that is eligible to all Texas Gas employees hired prior to November 1, 2006. Participants in the plan vest after three years of credited service. One year of vesting service is earned for each calendar year in which a participant completes 1,000 hours of service. Eligible compensation used in calculating the plan's annual compensation credits include total salary and bonus paid. The credit rate on all eligible compensation is 4.5% prior to age 30, 6.0% age 30 through 39, 8.0% age 40 through 49 and 10.0% age 50 and older up to the Social Security Wage Base. Additional credit rates on annual pay above Social Security Wage Base is 1.0%, 2.0%, 3.0% and 5.0% for the same age categories. On April 1, 1998, the TGRP was converted to a cash balance plan. Credited service up to March 31, 1998, is eligible for a past service credit of 0.3%. Additionally, participants may qualify for an early retirement subsidy if their combined age and

service at March 31, 1998, totaled at least 55 points. The amount of the subsidy is dependent on the number of points and the participant's age of retirement. Mr. Buskill did not meet the eligibility requirements to qualify for the early retirement subsidy. Upon retirement, the retiree may choose to receive their benefit from a variety of payment options which include a single life annuity, joint and survivor annuity options and a lump-sum cash payment. Joint and survivor benefit elections serve to reduce the amount of the monthly benefit payment paid during the retiree's life but the monthly payments continue for the life of the survivor after the death of the retiree. The TGRP has an early retirement provision that allows vested employees to retire early at age 55. Mr. Buskill is not yet eligible to receive an early retirement benefit pursuant to the TGRP.

The credited years of service appearing in the table above are the same as actual years of service. No payment was made to the Named Executive Officer during 2011. The present value of accumulated benefits payable to the Named Executive Officer, including the number of years of service credited to the Named Executive Officer, is determined using assumptions consistent with the assumptions used for financial reporting. Interest will be credited to the cash balance at December 31, 2011, commencing in 2012, using a quarterly compounding up to the normal retirement date of age 65. Salary and bonus pay credits, up to the IRC allowable limits, increase the accumulated cash balance in the year earned. Credited interest rates used to determine the accumulated cash balance at the normal retirement date as of December 31, 2011, 2010 and 2009 were 3.77%, 4.19% and 4.27% and for future years, 3.18%, 3.77% and 4.19%. The future normal retirement date accumulated cash balance was then discounted using an interest rate at December 31, 2011, 2010 and 2009 of 4.25%, 5.00% and 5.70%. The increase in the present value of accumulated benefit for the TGRP between December 31, 2011 and 2010 of \$49,397 for Mr. Buskill is reported as compensation in the Summary Compensation Table above.

The Texas Gas SRP is a non-qualified defined benefit cash balance plan that provides supplemental retirement benefits on behalf of participating employees for earnings that exceed the IRC compensation limitations for qualified defined benefit plans, which for 2011 was \$245,000. The SRP acts as a supplemental plan, therefore the eligibility and retirement provisions, the form and timing of distributions and the manner in which the present value of accumulated benefits are calculated, are identical to the same provisions as described above for the TGRP. The increase in the present value of accumulated benefit for the SRP between December 31, 2011 and 2010, of \$62,333, for Mr. Buskill is reported as compensation in the Summary Compensation Table.

Potential Payments Upon Termination or Change of Control

We do not have employment agreements with our Named Executive Officers, other than a one-year agreement with Mr. Horton, which is discussed further under *Narrative Disclosure to Summary Compensation Table and Grant of Plan Based Awards Table*. Potential payments made under that agreement in the event of Mr. Horton's termination of employment with us or a change of control correspond to those that would be made under the applicable plans as described below.

Our Named Executive Officers are eligible to receive accelerated vesting of cash and equity-based awards under certain of our compensation plans. We have made grants of Phantom Common Units, UARs, Long-Term Cash Bonuses and Phantom GP Units to each of our executives subject to specific vesting schedules and payment limitations, as discussed above. The Phantom Common Units, UARs and Long-Term Cash Bonuses will vest on a prorated basis under certain circumstances and will be payable in accordance with the provisions of the LTIP, UAR and Cash Bonus Plan and grant agreements, as applicable, as described below. The Phantom GP Units awards will vest immediately and become payable to the executive in cash upon the occurrence of certain events, as described below. A termination of employment may also trigger a distribution of retirement plan accounts from the TGRP or the SRP. Any retirement plan distributions would be no more than those amounts disclosed in the tables above; thus, the Potential Payments Upon Termination or Change of Control Table shown below does not include amounts attributable to the retirement plans disclosed above.

We believe that the acceleration and payment provisions contained in our various award agreements create important retention tools for us, because providing for accelerated vesting of equity-based awards upon a termination of employment for a death or disability provides employees with value in the event of a termination of employment that was beyond their control. Other companies in our industry and the general market where we compete for executive talent commonly have equity compensation plans that provide for accelerated vesting upon

certain terminations of employment, and we have provided this benefit to our Named Executive Officers in order to remain competitive in attracting and retaining skilled professionals in our industry.

Long-Term Incentive Plan. A prorated portion of unvested Phantom Common Units (and all DERs associated with such Phantom Common Units) will become vested upon our change of control in combination with a termination of employment by the Partnership for any reason other than for a material violation of the Partnership's code of conduct policy or due to a diminution of the employee's roles and responsibilities. A change of control will be deemed to occur under our LTIP upon one or more of the following events: (a) any person or group, other than our general partner or its affiliates, becomes the owner of 50% or more of our equity interests; (b) any person, other than Loews Corporation or its affiliates, become our general partner; or (c) the sale or other disposition of all or substantially all of our assets or our general partner's assets to any person that is not an affiliate of us or our general partner. However, in the event that any award granted under our LTIP is also subject to IRC section 409A, a change of control shall have the definition of such term as found in the treasury regulations with respect to IRC section 409A.

The unvested Phantom Common Units (and all DERs associated with such Phantom Common Units) will also become vested on a prorated basis upon an executive's death, disability or retirement (unless the retirement occurs in the first year of the vesting period, in which case the units will be forfeited). Our individual form award agreements define a disability as an event that would entitle that individual to benefits under either our or one of our affiliates' long-term disability plans (Disability). The award agreements define retirement as a termination on or after age 55, with at least 5 years of continuous service. In the cases of death or Disability, the value of any then vested awards would be determined and paid at the time of termination. In the case of retirement or change of control, the value of any then vested awards would be determined and paid on the original scheduled payment date. Other than described above, unvested Phantom Common Units would be forfeited upon termination of employment.

Unit Appreciation Rights and Cash Bonus Plan. For UARs granted in December 2011, a prorated portion of unvested UARs will become vested upon our change of control in combination with a termination of employment by the Partnership for any reason other than for a material violation of the Partnership's code of conduct policy or due to a diminution of the employee's roles and responsibilities. For UARs and Long-Term Cash Bonuses granted prior to December 2011, a change of control would not automatically affect the vesting or payment of the awards. However, upon a change of control, the Board in its sole discretion may provide for the replacement of awards with other rights or property; provide that awards be assumed or replaced by the surviving entity; make changes to the number or types of outstanding awards; provide that awards be concurrently vested and paid; or terminate any outstanding awards. A change of control will be deemed to occur under our UAR and Cash Bonus Plan upon a change in the possession, direct or indirect, of the power to direct or cause the direction of our management and policies, whether through ownership of voting securities, by contract or otherwise. However, in the event that any award granted under our UAR and Cash Bonus Plan is also subject to IRC section 409A, a change of control shall have the definition of such term as found in the treasury regulations with respect to IRC section 409A.

For the UARs and Long-Term Cash Bonuses granted prior to December, 2011, a prorated portion of any outstanding and unvested UARs and Long-Term Cash Bonuses would become vested upon an executive's death, Disability or retirement. For the UARs granted in December, 2011, a prorated portion of any outstanding and unvested UARs would become vested upon an executive's death, Disability or retirement (unless the retirement occurs in the first year of the vesting period, in which case the units will be forfeited). The award agreements for UARs granted in December, 2011 define retirement as a termination one or more years after the date of grant, on or after reaching age 55 with at least 5 years of continuous service with us. The award agreements for UARs and Long-Term Cash Bonuses granted prior to December, 2011 define retirement as a termination on or after age 55 with at least 10 years of continuous service.

For UARs and Long-Term Cash Bonuses granted prior to December 2011, termination by us without cause at least two years after the date of grant of the award would cause unvested awards to become vested on a prorated basis based on the date of the termination. Cause will first be defined as such term is used in any applicable employment agreement between the executive and us, and in the absence of such an employment agreement, as: (a) a federal or state felony conviction; (b) dishonesty in the fulfillment of an executive's employment or engagement; (c) the executive's willful and deliberate failure to perform his employment duties in any material respect; or (d) any other event that our board of directors, in good faith, determines to constitute cause.

For outstanding UARs and Long-Term Cash Bonuses, in the cases of death or Disability, or in the case of awards granted prior to December 2011, involuntary termination of employment, the value of any then vested awards would be determined and paid at the time of termination. For the December, 2011 awards, in the case of retirement or change of control combined with a termination of employment as discussed above, the value of any then vested awards would be determined and paid on the original scheduled payment date. Other than as described above, unvested UARs or Long-Term Cash Bonuses would be forfeited upon termination of employment.

Strategic Long-Term Incentive Plan. Our SLTIP requires a minimum distribution amount per common unit to be met prior to any payment with regard to a Phantom GP Unit, otherwise the Phantom GP Unit will be forfeited without payment. Since the minimum distribution amount for 2011 was achieved, the Phantom GP Units held by our Named Executive Officers would be eligible to receive accelerated vesting and payout upon certain events.

All unvested Phantom GP Units will become vested upon our general partner's change of control. The SLTIP defines a change of control as one or more of the following events: (a) any person or group, other than our general partner's affiliates, becomes the owner of 50% or more of our general partner's equity interests; (b) any person, other than Loews Inc. or its affiliates, becomes the general partner of our general partner; or (c) the sale or other disposition of all or substantially all of our general partner's, or the general partner of our general partner's, assets to any person that is not an affiliate of our general partner or its general partner. As with the LTIP and UAR and Cash Bonus Plan, if the Phantom GP Units are subject to IRC section 409A, the change of control definition will be the meaning of such term as found in the treasury regulations with respect to IRC section 409A.

Unvested Phantom GP Units will also vest upon a participant's death, Disability, retirement, or a termination of employment other than for cause. The award agreements define retirement as a termination on or after age 65 other than for cause (as defined below) or a termination of employment other than for cause, with the consent of our board of directors, on or after the age of 60. Cause is defined as above for UARs and Long-Term Cash Bonuses.

Paid Time Off (PTO). Upon any termination of employment, the Named Executive Officers would receive the remaining accrued paid time off that they accumulated during the year, if any.

Potential Payments Upon Termination or Change of Control Table

The following table represents our estimate of the amount each of our Named Executive Officers would have received upon the applicable termination or change of control event, if such event had occurred on December 31, 2011. The closing price of our common units on the NYSE on December 31, 2011, \$27.67, was used to calculate these amounts. The amounts that any Named Executive Officer could receive upon a termination of employment or a change of control cannot be determined with any certainty until an actual termination of employment or a change of control occurs. For purposes of the below table, we have assumed all salary and bonuses were paid current as of December 31, 2011, and excludes the LTIP awards (Phantom Common Units) that vested in December 2011 and were paid in January 2012. See *Option Exercises and Stock Vested* for further discussion

Potential Payments Upon Termination or Change of Control at December 31, 2011						
Name	Plan Name	Change of Control (1) (\$)	Termination Other than for Cause (\$)	Termination for Cause, or Voluntary Resignation (\$)	Retirement (2) (\$)	Death or Disability (\$)
Stanley C. Horton	UAR and Cash Bonus Plan (3)	4,359	-	-	-	103,390
	LTIP (4)	15,342	-	-	-	15,342
	PTO (6)	9,231	9,231	9,231	9,231	9,231
	Total	28,932	9,231	9,231	9,231	127,963
Rolf A. Gafvert	UAR and Cash Bonus Plan (3)	-	-	-	167,992	167,992
	SLTIP (5)	2,094,248	2,094,248	-	-	2,094,248
	PTO (6)	46,587	46,587	46,587	46,587	46,587
	Total	2,140,835	2,140,835	46,587	214,579	2,308,827
Jamie L. Buskill (7)	UAR and Cash Bonus Plan (3)	1,677	-	-	-	95,006
	LTIP (4)	5,901	-	-	-	5,901
	SLTIP (5)	1,005,239	1,005,239	-	-	1,005,239
	PTO (6)	7,500	7,500	7,500	7,500	7,500
	Total	1,020,317	1,012,739	7,500	7,500	1,113,646
Brian A. Cody	UAR and Cash Bonus Plan (3)	1,006	-	-	-	94,335
	LTIP (4)	3,541	-	-	-	3,541
	SLTIP (5)	921,469	921,469	-	-	921,469
	PTO (6)	5,769	5,769	5,769	5,769	5,769
	Total	931,785	927,238	5,769	5,769	1,025,114
Michael E. McMahon	UAR and Cash Bonus Plan (3)	1,451	--	-	60,663	62,114
	LTIP (4)	4,130	-	-	-	4,130
	SLTIP (5)	879,584	879,584	-	-	879,584
	PTO (6)	9,173	9,173	9,173	9,173	9,173
	Total	894,338	888,757	9,173	69,836	955,001

- (1) The amounts listed under the Change of Control column will apply only in the event that the change of control definition for that particular plan has been triggered.
- (2) As of December 31, 2011, Messrs. Gafvert and McMahon were eligible for retirement as defined in the LTIP and UAR and Cash Bonus Plan award agreements (each as defined above). None of the Named Executive Officers were eligible for retirement as defined in the SLTIP. The determination of amounts to be paid and the timing of payments applicable to awards under the UAR and Cash Bonus Plan would not be affected by an event of retirement.
- (3) UAR and Cash Bonus Plan amounts were determined by multiplying the prorated number of unvested UARs each executive held on December 31, 2011, by the value obtained using the plan formula, and adding the prorated amount of Long-Term Cash Bonuses that would become vested and payable. The assumed proration factors at December 31, 2011, were 0.016 for awards issued in December, 2011, 0.20 for awards made in June, 2011 and 0.35 for awards issued in 2010. No cash distributions were paid on behalf of our common units during the period the UARs granted in December, 2011 were outstanding, therefore no DER Adjustment was applied to the exercise price for those awards. The DER Adjustment through December 31, 2011 applicable to each UAR granted in June, 2011 and in 2010 was \$1.0525 and \$2.095, respectively. For the UARs granted in December, 2011, June, 2011 and in 2010, the excess of the closing price of our common units on December 31, 2011 over the exercise price reduced by the applicable DER Adjustment, was \$0.37, zero and zero, respectively. These resulting amounts were below the UAR Caps of zero, \$12.67 and \$15.76 applicable to the December, 2011, June, 2011 and 2010 grants, respectively. As of December 31, 2011, Messrs. Horton, Gafvert, Buskill, Cody and McMahon held 111,512, zero, 15,475, 9,285 and 10,832 UARs which were granted in 2011 and zero, 59,886, 33,270, 33,270 and 21,625 UARs which were granted in 2010. Messrs. Horton, Gafvert, Buskill, Cody and McMahon held Long-Term Cash Bonuses of \$258,000, \$270,000, \$150,000, \$150,000 and \$97,500, respectively.
- (4) LTIP amounts were determined by multiplying the prorated number of unvested Phantom Common Units each executive held on December 31, 2011, by the value of our common units on that date, or \$27.67. The assumed proration factor at December 31 was 0.016 for the outstanding awards. As of December 31, 2011, Messrs. Horton, Gafvert, Buskill, Cody and McMahon held Phantom Common Units of 35,714, zero, 13,736, 8,242 and 9,615, respectively. No cash distributions were paid on behalf of our common units during the period these Phantom Common Units were outstanding, therefore no amounts were credited to the DERs associated with these awards through December 31, 2011.
- (5) SLTIP amounts were determined by multiplying the number of unvested Phantom GP Units each executive held on December 31, 2011, by the value of each GP unit on that date based upon full vesting of outstanding awards and valued using the plan formula value assuming cash distributions made by the Partnership to our general partner for the four consecutive quarters ending on December 31, 2011, of \$32.1 million and an implied yield on our common units of 7.66% at December 31, 2011. As of December 31, 2011, Messrs. Gafvert, Buskill, Cody and McMahon held 50, 24, 22 and 21 Phantom GP Units, respectively.
- (6) Includes earned but unused paid time off at December 31, 2011. In order to receive PTO payments upon retirement, the employee must have provided us with at least a six month notice prior to the termination of his employment.
- (7) Mr. Buskill would also be entitled to receive payment under the SRP six months after termination for any reason, which amounts are reported in the Pension Benefits table.

Director Compensation

Each director of BGL who is not an officer or employee of us, our subsidiaries, our general partner or an affiliate of our general partner (an Eligible Director) is paid an annual cash retainer of \$35,000 (\$40,000 for the chairman of the Audit Committee), payable in equal quarterly installments, \$1,000 for each Board meeting attended which is not a regularly scheduled meeting, and an annual grant of 500 of our common units. Directors who are not Eligible Directors do not receive compensation from us for their services as directors. All directors are reimbursed for out-of-pocket expenses they incur in connection with attending Board and committee meetings and will be fully indemnified by us for actions associated with being a director to the extent permitted under Delaware law. The following table displays information related to compensation paid to our Eligible Directors for 2011:

Director Compensation for 2011			
Name	Fees Earned or Paid in Cash (\$)	Stock Awards (1) (\$)	Total (\$)
Arthur L. Rebell	46,000	16,410	62,410
William R. Cordes	48,000	16,410	64,410
Thomas E. Hyland (2)	57,000	16,410	73,410
Mark L. Shapiro	48,000	16,410	64,410

- (1) On February 28, 2011, Messrs. Rebell, Cordes, Hyland and Shapiro were each granted 500 common units. The total grant date fair value of the award for each Eligible Director, based on the closing market price of \$32.82, was \$16,410.
- (2) Chairman of the Audit Committee.

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

The following table sets forth certain information, at February 21, 2012, as to the beneficial ownership of our common and class B units by beneficial holders of 5% or more of either such class of units, each member of our Board, each of the Named Executive Officers and all of our executive officers and directors as a group, based on data furnished by them. None of the parties listed in the table have the right to acquire units within 60 days:

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned (1)	Class B Units Beneficially Owned	Percentage of Class B Units Beneficially Owned (1)	Percentage of Total Limited Partner Units Beneficially Owned
Stanley C. Horton	1,000 ⁽²⁾	-	-	-	*
Jamie L. Buskill	-	-	-	-	-
Brian A. Cody	-	-	-	-	-
William R. Cordes	2,500	*	-	-	*
Thomas E. Hyland	8,400 ⁽³⁾	*	-	-	*
Michael E. McMahon	-	-	-	-	-
Jonathan E. Nathanson	15,000 ⁽⁴⁾	*	-	-	*
Arthur L. Rebell	39,875 ⁽⁵⁾	*	-	-	*
Mark L. Shapiro	13,000	*	-	-	*
Kenneth I. Siegel	-	-	-	-	-
Andrew H. Tisch	81,050 ⁽⁶⁾	*	-	-	*
All directors and executive officers as a group	160,825	*	-	-	*
BPHC ⁽⁷⁾	102,719,466	56%	22,866,667	100%	60%
Loews Corporation ⁽⁷⁾	102,719,466	56%	22,866,667	100%	60%

*Represents less than 1% of the outstanding common units

- (1) As of February 21, 2012, we had 184,921,916 common units and 22,866,667 class B units issued and outstanding.
- (2) 1,000 units are owned by Mr. Horton's spouse.
- (3) 400 of these units are owned by Mr. Hyland's spouse.
- (4) 15,000 units are owned by Mr. Nathanson's spouse.
- (5) 32,984 of these units are owned by AREbell, LLC, a limited liability company controlled by Mr. Rebell.
- (6) Represents one quarter of the number of units owned by a general partnership in which a one-quarter interest is held by a trust of which Mr. Tisch is managing trustee.
- (7) Loews Corporation is the parent company of BPHC and may, therefore, be deemed to beneficially own the units held by BPHC. The address of BPHC is 9 Greenway Plaza, Suite 2800, Houston, TX 77046. The address of Loews is 667 Madison Avenue, New York, New York 10065. Boardwalk GP, an indirect, wholly-owned subsidiary of BPHC, also holds the 2% general partner interest and all of our IDRs. Including the general partner interest but excluding the impact of the IDRs, Loews indirectly owns approximately 61% of our total ownership interests. *Our Partnership Interests* in Item 5 contains more information regarding our calculation of BPHC's equity ownership.

Securities Authorized for Issuance Under Equity Compensation Plans

In 2005, prior to the initial public offering of our common units, our Board adopted the Boardwalk Pipeline Partners, LP Long-Term Incentive Plan. The following table provides certain information as of December 31, 2011, with respect to this plan:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plan (excluding securities reflected in the first column)
Equity compensation plans approved by security holders	-	N/A	-
Equity compensation plans not approved by security holders	-	N/A	3,515,708

Note 9 in Item 8 of this Report contains more information regarding our equity compensation plan.

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

It is our Board's written policy that any transaction, regardless of the size or amount involved, involving us or any of our subsidiaries in which any related person had or will have a direct or indirect material interest shall be reviewed by, and shall be subject to approval or ratification by our Conflicts Committee. "Related person" means our general partner and its directors and executive officers, holders of more than 5% of our units, and in each case, their "immediate family members," including any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law, or sister-in-law, and any person (other than a tenant or employee) sharing their household. In order to effectuate this policy, our General Counsel reviews all such transactions and reports thereon to the Conflicts Committee for its consideration. Our General Counsel also determines whether any such transaction presents a potential conflict of interest under our partnership agreement and, if so, presents the transaction to our Conflicts Committee for its consideration. In the event of a continuing service provided by a related person, the transaction is initially approved by the Conflicts Committee but may not be subject to subsequent approval. However, the Board approves the Partnership's annual operating budget which separately states the amounts expected to be charged by related parties or affiliates for the following year. No new service transactions were reviewed for approval by the Conflicts Committee during 2011 nor were there any service transactions where the policy was not followed.

Distributions are approved by the Board on a quarterly basis prior to declaration. Note 10 and Note 15 in Item 8 of this Report contain more information regarding our related party transactions.

See Item 10, *Our Independent Directors* for information regarding director independence.

Item 14. Principal Accounting Fees and Services

Audit Fees and Services

The following table presents fees billed by Deloitte & Touche LLP and its affiliates for professional services rendered to us and our subsidiaries in 2011 and 2010 by category as described in the notes to the table (in millions):

	<u>2011</u>	<u>2010</u>
Audit fees ⁽¹⁾	\$ 2.1	\$ 2.0
Audit related fees ⁽²⁾	<u>0.5</u>	<u>0.2</u>
Total	<u>\$ 2.6</u>	<u>\$ 2.2</u>

(1) Includes the aggregate fees and expenses for annual financial statement audit and quarterly financial statement reviews.

(2) Includes the aggregate fees and expenses for services that were reasonably related to the performance of the financial statement audits or reviews described above and not included under Audit fees above, mainly including due diligence, consents, comfort letters and audits of employee benefits plans.

Auditor Engagement Pre-Approval Policy

In order to assure the continued independence of our independent auditor, currently Deloitte & Touche LLP, the Audit Committee has adopted a policy requiring its pre-approval of all audit and non-audit services performed for us and our subsidiaries by the independent auditor. Under this policy, the Audit Committee annually pre-approves certain limited, specified recurring services which may be provided by Deloitte & Touche, subject to maximum dollar limitations. All other engagements for services to be performed by Deloitte & Touche must be specifically pre-approved by the Audit Committee, or a designated committee member to whom this authority has been delegated.

Since the formation of the Audit Committee and its adoption of this policy in November 2005, the Audit Committee, or a designated member, has pre-approved all engagements by us and our subsidiaries for services of Deloitte & Touche, including the terms and fees thereof, and the Audit Committee concluded that all such engagements were compatible with the continued independence of Deloitte & Touche in serving as our independent auditor.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. Financial Statements

Included in Item 8 of this report:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets at December 31, 2011 and 2010

Consolidated Statements of Income for the years ended December 31, 2011, 2010 and 2009

Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009

Consolidated Statements of Changes in Partners' Capital for the years ended December 31, 2011, 2010 and 2009

Consolidated Statements of Comprehensive Income for the years ended December 31, 2011, 2010 and 2009

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules

Valuation and Qualifying Accounts

The following table presents those accounts that have a reserve as of December 31, 2011, 2010 and 2009 and are not included in specific schedules herein. These amounts have been deducted from the respective assets on the Consolidated Balance Sheets (in millions):

Description	Balance at Beginning of Period	Additions:			Balance at End of Period
		Charged to Costs and Expenses	Other Additions	Deductions	
Allowance for doubtful accounts:					
2011	\$ 0.6	\$ 0.3	\$ -	\$ (0.7)	\$ 0.2
2010	0.3	0.4	-	(0.1)	0.6
2009	0.3	0.3	-	(0.3)	0.3

(a) 3. Exhibits

The following documents are filed as exhibits to this report:

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Boardwalk Pipeline Partners, LP (Incorporated by reference to Exhibit 3.1 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on August 16, 2005).
3.2	Third Amended and Restated Agreement of Limited Partnership of Boardwalk Pipeline Partners, LP dated as of June 17, 2008, (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed on June 18, 2008).
3.3	Certificate of Limited Partnership of Boardwalk GP, LP (Incorporated by reference to Exhibit 3.3 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on August 16, 2005).
3.4	Agreement of Limited Partnership of Boardwalk GP, LP (Incorporated by reference to Exhibit 3.4 to Amendment No. 1 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on September 22, 2005).
3.5	Certificate of Formation of Boardwalk GP, LLC (Incorporated by reference to Exhibit 3.5 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on August 16, 2005).
3.6	Amended and Restated Limited Liability Company Agreement of Boardwalk GP, LLC (Incorporated by reference to Exhibit 3.6 to Amendment No. 4 to Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on October 31, 2005).
3.7	Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of Boardwalk Pipeline Partners, LP, dated as of October 31, 2011 (Incorporated by reference to Exhibit 3.7 to the Registrant's Quarterly Report on Form 10-Q filed on November 1, 2011).
4.1	Amended and Restated Registration Rights Agreement dated June 26 2009, by and between Boardwalk Pipeline Partners, LP and Boardwalk Pipelines Holding Corp. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on June 26, 2009).
4.2	Indenture dated July 15, 1997, between Texas Gas Transmission Corporation (now known as Texas Gas Transmission, LLC) and The Bank of New York, as Trustee (Incorporated by reference to Exhibit 4.1 to Texas Gas Transmission Corporation's Registration Statement on Form S-3, Registration No. 333-27359, filed on May 19, 1997).
4.3	Indenture dated as of May 28, 2003, between TGT Pipeline, LLC and The Bank of New York, as Trustee (Incorporated by reference to Exhibit 3.6 to TGT Pipeline, LLC's (now known as Boardwalk Pipelines, LP) Registration Statement on Form S-4, Registration No. 333-108693, filed on September 11, 2003).
4.4	Indenture dated as of May 28, 2003, between Texas Gas Transmission, LLC and The Bank of New York, as Trustee (Incorporated by reference to Exhibit 3.5 to Boardwalk Pipelines, LLC's (now known as Boardwalk Pipelines, LP) Registration Statement on Form S-4, Registration No. 333-108693, filed on September 11, 2003).

- 4.5 Indenture dated as of January 18, 2005, between TGT Pipeline, LLC and The Bank of New York, as Trustee, (Incorporated by reference to Exhibit 10.1 to TGT Pipeline, LLC's (now known as Boardwalk Pipelines, LP) Current Report on Form 8-K filed on January 24, 2005).
- 4.6 Indenture dated as of January 18, 2005, between Gulf South Pipeline Company, LP and The Bank of New York, as Trustee (Incorporated by reference to Exhibit 10.2 to Boardwalk Pipelines, LLC's (now known as Boardwalk Pipelines, LP) Current Report on Form 8-K filed on January 24, 2005).
- 4.7 Indenture dated as of November 21, 2006, between Boardwalk Pipelines, LP, as issuer, the Registrant, as guarantor, and The Bank of New York Trust Company, N.A., as Trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on November 22, 2006).
- 4.8 Indenture dated August 17, 2007, between Gulf South Pipeline Company, LP and the Bank of New York Trust Company, N.A. therein (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on August 17, 2007).
- 4.9 Indenture dated August 17, 2007, between Gulf South Pipeline Company, LP and the Bank of New York Trust Company, N.A. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on August 17, 2007).
- 4.10 Indenture dated March 27, 2008, between Texas Gas Transmission, LLC and the Bank of New York Trust Company, N.A. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on March 27, 2008).
- 4.11 Indenture dated January 19, 2011, between Texas Gas Transmission, LLC and the Bank of New York Trust Company, N.A. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on January 19, 2011).
- 4.12 First Supplemental Indenture dated June 7, 2011, between Texas Gas Transmission, LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current report on Form 8-K, filed on June 13, 2011).
- 4.13 Second Supplemental Indenture dated June 16, 2011, between Texas Gas Transmission, LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee (incorporated by reference to Exhibit 4.1 to the Registrant's Current report on Form 8-K, filed on June 20, 2011).
- 4.14 Subordination Agreement, dated as of May 1, 2009, among Boardwalk Pipelines Holding Corp., as Subordinated Creditor, Wachovia Bank, National Association, as Senior Creditor Representative, and Boardwalk Pipelines, LP, as Borrower (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on May 5, 2009).
- 4.15 Indenture dated August 21, 2009, by and among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to Boardwalk Pipeline Partners, LP's Current Report on Form 8-K, filed on August 21, 2009).
- 4.16 First Supplemental Indenture dated August 21, 2009, by and among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.2 to Boardwalk Pipeline Partners, LP's Current Report on Form 8-K, filed on August 21, 2009).

- 10.1 Amended and Restated Revolving Credit Agreement, dated as of June 29, 2006, among Boardwalk Pipelines, LP, Boardwalk Pipeline Partners, LP, the several banks and other financial institutions or entities parties to the agreement as lenders, the issuers party to the agreement, Wachovia Bank, National Association, as administrative agent for the lenders and the issuers, Citibank, N.A., as syndication agent, JPMorgan Chase Bank, N.A., Deutsche Bank Securities, Inc. and Union Bank of California, N.A., as co-documentation agents, and Wachovia Capital Markets LLC and Citigroup Global Markets Inc., as joint lead arrangers and joint book managers (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on July 5, 2006).
- 10.2 Amendment No. 1 to Amended and Restated Revolving Credit Agreement, dated as of April 2, 2007, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, each a wholly-owned subsidiary of the Registrant, as Borrowers, and the agent and lender parties identified therein (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on April 5, 2007).
- 10.3 Amendment No. 2 to Amended and Restated Revolving Credit Agreement, dated as of November 27, 2007, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, and the agent and lender parties identified therein (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on November 29, 2007).
- 10.4 Amendment No. 3 to Amended and Restated Revolving Credit Agreement, dated as of March 6, 2008, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, and the agent and lender parties identified therein. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed on April 29, 2008).
- 10.5 Amendment No. 4 to Amended and Restated Revolving Credit Agreement, dated as of August 31, 2010, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, and the agent and lender parties identified therein. (Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q filed on November 1, 2011).
- 10.6 Amendment No. 5 to Amended and Restated Revolving Credit Agreement, dated as of June 3, 2011, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, and the agent and lender parties identified therein. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed on August 3, 2011).
- *10.7 Amendment No. 6 to Amended and Restated Revolving Credit Agreement, dated as of January 19, 2012, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, and the agent and lender parties identified therein.
- 10.8 Services Agreement dated as of May 16, 2003, by and between Loews Corporation and Texas Gas Transmission, LLC. (Incorporated by reference to Exhibit 10.8 to Amendment No. 3 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on October 24, 2005). (1)
- **10.9 Boardwalk Pipeline Partners, LP Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.9 to Amendment No. 4 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on October 31, 2005).

- **10.10 Form of Phantom Unit Award Agreement under the Boardwalk Pipeline Partners, LP Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.10 to the Registrant's 2005 Annual Report on Form 10-K filed on March 16, 2006).
- **10.11 Boardwalk Pipeline Partners, LP Strategic Long-Term Incentive Plan (Incorporated by reference to Exhibits 10.1 and 10.2 to the Registrant's Current Report on Form 8-K filed on July 28, 2006).
- **10.12 Form of GP Phantom Unit Award Agreement under the Boardwalk Pipeline Partners, LP Strategic Long-Term Incentive Plan (Incorporated by reference to Exhibits 10.1 and 10.2 to the Registrant's Current Report on Form 8-K filed on July 28, 2006).
- **10.13 Boardwalk Operating GP, LLC Short-Term Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed on April 27, 2010).
- **10.14 Boardwalk Pipeline Partners Unit Appreciation Rights and Cash Bonus Plan (Incorporated by reference to Exhibit 10.1 and 10.2 to the Registrant's Current Report on Form 8-K filed on December 17, 2010).
- **10.15 Form of Grant of UARs and Cash Bonus under the Boardwalk Pipeline Partners Unit Appreciation Rights and Cash Bonus Plan (Incorporated by reference to Exhibit 10.1 and 10.2 to the Registrant's Current Report on Form 8-K filed on December 17, 2010).
- **10.16 Form of Grant of Phantom Units with DERs under the Boardwalk Pipeline Partners Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on December 20, 2011).
- 10.17 Subordinated Loan Agreement dated as of May 1, 2009 between Boardwalk Pipelines, LP, as Borrower, and Boardwalk Pipelines Holding Corp., as Lender (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on May 5, 2009).
- **10.18 Employment agreement between Boardwalk GP, LLC and Stanley C. Horton (incorporated by reference to Exhibit 10.5 to the Registrant's Current report on Form 8-K, filed on May 2, 2011).
- 10.19 Limited Liability Company Agreement of Boardwalk HP Storage Company, LLC dated as of October 16, 2011 (Incorporated by reference to Exhibit 10.4 to the Registrant's Quarterly Report on Form 10-Q filed on November 1, 2011).
- 10.20 Letter agreement between Boardwalk Pipelines, LP and Boardwalk Pipelines Holding Corp. dated as of October 16, 2011 (Incorporated by reference to Exhibit 10.5 to the Registrant's Quarterly Report on Form 10-Q filed on November 1, 2011).
- *21.1 List of Subsidiaries of the Registrant.
- *23.1 Consent Of Independent Registered Public Accounting Firm.
- *31.1 Certification of Stanley C. Horton, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a).
- *31.2 Certification of Jamie L. Buskill, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a).
- *32.1 Certification of Stanley C. Horton, Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

- *32.2 Certification of Jamie L. Buskill, Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- *101.INS XBRL Instance Document
- *101.SCH XBRL Taxonomy Extension Schema Document
- *101.CAL XBRL Taxonomy Calculation Linkbase Document
- *101.DEF XBRL Taxonomy Extension Definitions Document
- *101.LAB XBRL Taxonomy Label Linkbase Document
- *101.PRE XBRL Taxonomy Presentation Linkbase Document
- * Filed herewith
- ** Management contract or compensatory plan or arrangement

(1) The Services Agreements between Gulf South Pipeline Company, LP and Loews Corporation and between Boardwalk Pipelines, LP (formerly known as Boardwalk Pipelines, LLC) and Loews Corporation are not filed because they are identical to exhibit 10.11 except for the identities of Gulf South Pipeline Company, LP and Boardwalk Pipelines, LLC and the date of the agreement.

SIGNATURE

Pursuant to the requirements of Section 13 or 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.

Boardwalk Pipeline Partners, LP

By: Boardwalk GP, LP

its general partner

By: Boardwalk GP, LLC

its general partner

Dated: February 21, 2012

By: /s/ Jamie L. Buskill

Jamie L. Buskill

Senior Vice President, Chief Financial Officer and Treasurer

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 date indicated.

Dated: February 21, 2012

/s/ Stanley C. Horton

Stanley C. Horton

President, Chief Executive Officer and Director

(principal executive officer)

Dated: February 21, 2012

/s/ Jamie L. Buskill

Jamie L. Buskill

Senior Vice President, Chief Financial Officer and Treasurer

(principal financial officer)

Dated: February 21, 2012

/s/ Steven A. Barkauskas

Steven A. Barkauskas

Senior Vice President, Controller and Chief Accounting Officer

(principal accounting officer)

Dated: February 21, 2012

/s/ William R. Cordes

William R. Cordes

Director

Dated: February 21, 2012

/s/ Thomas E. Hyland

Thomas E. Hyland

Director

Dated: February 21, 2012

/s/ Arthur L. Rebell

Arthur L. Rebell

Director

Dated: February 21, 2012

/s/ Mark L. Shapiro

Mark L. Shapiro

Director

Dated: February 21, 2012

/s/ Kenneth I. Siegel

Kenneth I. Siegel

Director

Dated: February 21, 2012

/s/ Andrew H. Tisch

Andrew H. Tisch

Director

EXHIBIT 21.1**BOARDWALK PIPELINE PARTNERS, LP**
Subsidiaries of the Registrant
December 31, 2011

<u>Name of Subsidiary</u>	<u>Organized Under Laws of</u>	<u>Business Names</u>
Boardwalk Operating GP, LLC	Delaware	
Boardwalk Pipelines, LP	Delaware	
Texas Gas Transmission, LLC	Delaware	Texas Gas
Gulf South Pipeline Company, LP	Delaware	Gulf South
GS Pipeline Company, LLC	Delaware	
Gulf Crossing Pipeline Company LLC	Delaware	Gulf Crossing
Boardwalk Midstream, LP	Delaware	
Boardwalk Field Services, LLC	Delaware	Field Services

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-166373 on Form S-3 of our reports dated February 21, 2012, relating to the consolidated financial statements and financial statement schedule of Boardwalk Pipeline Partners, LP, and the effectiveness of Boardwalk Pipeline Partners, LP's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Boardwalk Pipeline Partners, LP for the year ended December 31, 2011.

/s/ Deloitte & Touche LLP
Houston, Texas
February 21, 2012

EXHIBIT 31.1

I, Stanley C. Horton, certify that:

- 1) I have reviewed this Annual Report on Form 10-K of Boardwalk Pipeline Partners, LP;
- 2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
- 3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
- 4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
- 5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 21, 2012

/s/ Stanley C. Horton

Stanley C. Horton

President, Chief Executive Officer and Director

EXHIBIT 31.2

I, Jamie L. Buskill, certify that:

- 1) I have reviewed this Annual Report on Form 10-K of Boardwalk Pipeline Partners, LP;
- 2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
- 3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
- 4) The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
- 5) The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 21, 2012

/s/ Jamie L. Buskill

Jamie L. Buskill

Senior Vice President, Chief Financial Officer and Treasurer

**Certification by the Chief Executive Officer
of
Boardwalk GP, LLC
pursuant to 18 U.S.C. Section 1350
(as adopted by Section 906 of the Sarbanes-Oxley Act of 2002)**

Pursuant to 18 U.S.C. Section 1350, the undersigned chief executive officer of Boardwalk GP, LLC hereby certifies, to such officer's knowledge, that the annual report on Form 10-K for the year ended December 31, 2011, (the Report) of Boardwalk Pipeline Partners, LP (the Partnership) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

February 21, 2012

/s/ Stanley C. Horton

Stanley C. Horton
President, Chief Executive Officer and Director
(principal executive officer)

**Certification by the Chief Financial Officer
of
Boardwalk GP, LLC
pursuant to 18 U.S.C. Section 1350
(as adopted by Section 906 of the Sarbanes-Oxley Act of 2002)**

Pursuant to 18 U.S.C. Section 1350, the undersigned chief financial officer of Boardwalk GP, LLC hereby certifies, to such officer's knowledge, that the annual report on Form 10-K for the year ended December 31, 2011, (the Report) of Boardwalk Pipeline Partners, LP (the Partnership) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

February 21, 2012

/s/ Jamie L. Buskill

Jamie L. Buskill

Senior Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

AMENDMENT NO. 6

AMENDMENT NO. 6, dated as of January 19, 2012 (this "*Amendment*"), by and among BOARDWALK PIPELINES, LP, a Delaware limited partnership (the "*Parent Borrower*"), TEXAS GAS TRANSMISSION, LLC, a Delaware limited liability company ("*Texas Gas*"), and GULF SOUTH PIPELINE COMPANY, LP, a Delaware limited partnership ("*Gulf South*" and, together with the Parent Borrower and Texas Gas, the "*Borrowers*"), severally as Borrowers, BOARDWALK PIPELINE PARTNERS, LP, a Delaware limited partnership (the "*MLP*"), the Lenders party hereto, and WELLS FARGO BANK, N.A. (as successor to Wachovia Bank, National Association), as administrative agent for the Lenders and the Issuers (in such capacity, the "*Administrative Agent*").

WITNESSETH:

WHEREAS, the Borrowers, the MLP, the Administrative Agent, the Lenders and the other parties thereto have entered into that certain Amended and Restated Revolving Credit Agreement, dated as of June 29, 2006 (as amended, supplemented or otherwise modified from time to time, the "*Credit Agreement*"); and

WHEREAS, the Borrowers have requested and the Lenders have agreed, subject to the terms and conditions hereinafter set forth, to amend the Credit Agreement as set forth below.

NOW, THEREFORE, in consideration of the foregoing, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereby agree as follows:

1. Defined Terms. Capitalized terms used herein and not otherwise defined herein shall have the meanings ascribed to such terms in the Credit Agreement.

2. Amendment. Effective as of the Effective Date (as defined below) and subject to the terms and conditions contained herein, the Credit Agreement is hereby amended as follows:

(a) The definition of Consolidated Leverage Ratio in *Section 1.1 (Defined Terms)* of the Credit Agreement is hereby amended and restated in its entirety to read as follows:

““*Consolidated Leverage Ratio*”: with respect to any Person as of any date, the ratio of (a) Consolidated Total Debt of such Person and its Subsidiaries on such date to (b) Consolidated EBITDA of such Person and its Subsidiaries for the last four Fiscal Quarter period ending on or before such date; *provided, however*, that Consolidated Total Debt shall exclude (i) any Subordinated Loans made by the Permitted Investor or any Subsidiary thereof to the MLP or any Borrower; *provided*, that the aggregate principal amount of such excluded Subordinated Loans pursuant to this clause (i) outstanding at any time shall not exceed \$200,000,000, (ii) any Subordinated Loans made by the MLP or any Borrower to any Borrower; *provided*, that the aggregate principal amount of such excluded Subordinated Loans pursuant to this clause (ii) outstanding at any time shall not exceed \$200,000,000, (iii) obligations of the Parent Borrower or any of its Subsidiaries under any Hybrid Securities and (iv) the aggregate principal amount of any Indebtedness of any non-Wholly Owned Subsidiary multiplied by the percentage of the economic interests of such non-Wholly Owned Subsidiary owned directly or indirectly by any Person other than the Borrowers or any Wholly Owned Subsidiary of the Borrowers, unless any Borrower or any Wholly-Owned Subsidiary of any Borrower has a Guarantee Obligation with respect to such Indebtedness, in which case the aggregate principal amount of such Indebtedness so guaranteed shall be included in the calculation of Consolidated Total Debt.”

EXHIBIT 10.7

(b) *Section 7.1 (Limitations on Indebtedness)* of the Credit Agreement is hereby amended by deleting the word “and” at the end of subsection (b), replacing the period at the end of subsection (c) with “; and”, and adding the following subsection (d) in its entirety to read as follows:

“(d) Indebtedness of any Person that becomes a Subsidiary of any Borrower (other than Indebtedness issued as consideration in, or to provide all or any portion of the funds or credit support utilized to consummate, the transactions pursuant to which such Subsidiary became a Subsidiary of any Borrower) that is outstanding at the time such Person becomes a Subsidiary of any Borrower if, at the time such Person becomes a Subsidiary of any Borrower, and after giving effect to the incurrence of such Indebtedness, (i) such Borrower shall be in pro forma compliance with the financial covenant in Section 5, in each case determined as of the last day of the most recently ended Fiscal Quarter of such Borrower for which financial statements have been delivered to the Administrative Agent pursuant to Sections 6.1(a) or (b), as applicable, and (ii) no Default or Event of Default shall have occurred and be continuing.”

3. Conditions to Effectiveness of this Amendment. This Amendment shall become effective as of the date (the “*Effective Date*”) the Administrative Agent shall have received counterparts of this Amendment duly executed and delivered by each of the Borrowers, the MLP, the Administrative Agent, and the Required Lenders under the Credit Agreement.

4. Representations and Warranties. Each Loan Party hereby represents and warrants to the Administrative Agent and the Lenders, on and as of the date hereof, that:

(a) (i) Such Loan Party has taken all necessary action to authorize the execution, delivery and performance of this Amendment, (ii) this Amendment has been duly executed and delivered by such Loan Party and (iii) this Amendment is the legal, valid and binding obligation of such Loan Party, enforceable against it in accordance with its terms, except as enforceability may be limited by applicable bankruptcy, insolvency, reorganization, moratorium or similar laws affecting the enforcement of creditors’ rights generally and by general equitable principles.

(b) After giving effect to this Amendment, each of the representations and warranties made by any Loan Party in or pursuant to the Loan Documents (other than the representations and warranties set forth in Sections 3.2 and 3.6 of the Credit Agreement) is true and correct in all material respects on and as of the date hereof, as if made on and as of such date, except to the extent such representations and warranties expressly relate to an earlier date, in which case such representations and warranties are true and correct in all material respects as of such earlier date.

(c) After giving effect to this Amendment, no Default or Event of Default has occurred and is continuing as of the date hereof.

5. Reaffirmation.

(a) Each Loan Party hereby consents to the execution, delivery and performance of this Amendment and agrees that each reference to the Credit Agreement in the Loan Documents shall, on and after the Effective Date, be deemed to be a reference to the Credit Agreement as amended by this Amendment.

(b) Each Loan Party hereby acknowledges and agrees that, after giving effect to this Amendment, all of its respective obligations and liabilities under the Loan Documents to which it is a party are reaffirmed, and remain in full force and effect.

EXHIBIT 10.7

6. Continuing Effect. Except as expressly set forth in this Amendment, all of the terms and provisions of the Credit Agreement are and shall remain in full force and effect and the Borrower shall continue to be bound by all of such terms and provisions. The Amendment provided for herein is limited to the specific provisions of the Credit Agreement specified herein and shall not constitute an amendment of, or an indication of the Administrative Agent's or the Lenders' willingness to amend or waive, any other provisions of the Credit Agreement or the same sections for any other date or purpose.

7. Expenses. The Borrowers agree to pay and reimburse the Administrative Agent for all its reasonable out-of-pocket costs and expenses incurred in connection with the negotiation, preparation, execution and delivery of this Amendment, and other documents prepared in connection herewith, and the transactions contemplated hereby, including, without limitation, reasonable fees and disbursements and other charges of counsel to the Administrative Agent and the charges of SyndTrak Online relating to the Amendment.

8. Choice of Law. This Amendment and the rights and obligations of the parties hereto shall be governed by, and construed and interpreted in accordance with the law of the State of New York.

9. Counterparts. This Amendment may be executed in any number of counterparts and by different parties and separate counterparts, each of which when so executed and delivered, shall be deemed an original, and all of which, when taken together, shall constitute one and the same instrument. Delivery of an executed counterpart of a signature page to this Amendment by facsimile or e-mail shall be effective as delivery of a manually executed counterpart of this Amendment.

10. Integration. This Amendment, together with the other Loan Documents, incorporates all negotiations of the parties hereto with respect to the subject matter hereof and is the final expression and agreement of the parties hereto with respect to the subject matter hereof.

11. Severability. In case any provision in this Amendment shall be invalid, illegal or unenforceable, such provision shall be severable from the remainder of this Amendment and the validity, legality and enforceability of the remaining provisions shall not in any way be affected or impaired thereby.

12. Loan Document. This Amendment is a Loan Document.

13. Waiver of Jury Trial. EACH OF THE PARTIES HERETO IRREVOCABLY WAIVES TRIAL BY JURY IN ANY ACTION OR PROCEEDING WITH RESPECT TO THIS AMENDMENT AND ANY OTHER LOAN DOCUMENT.

[SIGNATURE PAGES FOLLOW]

EXHIBIT 10.7

IN WITNESS WHEREOF, the parties have entered into this Amendment as of the date first above written.

BOARDWALK PIPELINES, LP,
as Borrower

By: BOARDWALK OPERATING GP, LLC,
its general partner

By: BOARDWALK PIPELINE PARTNERS, LP,
its managing member

By: BOARDWALK GP, LP,
its general partner

By: BOARDWALK GP, LLC,
its general partner

By: _____
Name:
Title:

TEXAS GAS TRANSMISSION, LLC,
as Borrower

By: _____
Name:
Title:

GULF SOUTH PIPELINE COMPANY, LP,
as Borrower

By: GS PIPELINE COMPANY, LLC,
its general partner

By: _____
Name:
Title:

BOARDWALK PIPELINE PARTNERS, LP

By: BOARDWALK GP, LP,
its general partner

By: BOARDWALK GP, LLC,
its general partner

By: _____
Name:
Title:

EXHIBIT 10.7

WELLS FARGO BANK, N.A.,
as Administrative Agent and Lender

By: _____
Name:
Title:

EXHIBIT 10.7

_____,
as a Lender

By: _____
Name:
Title: