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, 2010

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:

Title of each class	*Name of each exchange on which registered*
Common Units Representing Limited Partner Interests	**New York Stock Exchange**

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 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, 2010, was approximately $2.0 billion. As of February 18, 2011, the registrant had 169,721,916 common units outstanding and 22,866,667 Class B units outstanding.

Documents incorporated by reference. <u>None.</u>

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2010 FORM 10-K

BOARDWALK PIPELINE PARTNERS, LP

PART I

Item 1. Business

Introduction

We are a Delaware limited partnership formed in 2005. Our business is conducted by our subsidiaries, 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). 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). The common units, class B units and general partner interest owned by BPHC represent approximately 66% 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).

Our Business

Through our subsidiaries, 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, interstate and intrastate pipelines, electric power generators and direct industrial users. 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, 2010, approximately 78% of our revenues were derived from capacity reservation charges under firm contracts, approximately 15% of our revenues were derived from charges based on actual utilization under firm contracts and approximately 7% of our revenues were derived from interruptible transportation, interruptible storage, parking and lending (PAL) and other services.

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 interconnected 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 2010, our pipeline systems transported approximately 2.5 trillion cubic feet (Tcf) of gas. Average daily throughput on our pipeline systems during 2010 was approximately 6.8 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. We conduct all of our natural gas transportation and integrated storage operations through our operating subsidiaries as one segment.

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 Caney 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; imported liquefied natural gas (LNG) through several Gulf Coast LNG terminals, one of which is directly connected to our pipeline systems; 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 for Gulf Crossing 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 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 each of our operating subsidiaries as of December 31, 2010:

Pipeline	Miles of Pipeline	Working Gas Storage Capacity	Peak-day Delivery Capacity	Average Daily Throughput
		(Bcf)	(Bcf/d)	(Bcf/d)
Gulf Crossing	360	-	1.7	1.3
Gulf South	7,700	83.0	6.8	4.1
Texas Gas	6,110	84.0	4.8	3.0

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, price of service 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 firm transportation contracts can be offered for terms greater than ten years or less than one year. 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, interstate and intrastate pipelines, electric power generators and direct industrial users 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 2010 revenues, our customer mix was as follows: producers (44%), LDCs (22%), marketers (19%), pipelines (11%), power generators (3%) and industrial end users and others (1%). Based upon 2010 revenues, our deliveries were as follows: pipeline interconnects (64%), LDCs (18%), storage activities (8%), industrial end-users (4%), power generators (3%) and other (3%). One customer, Devon Gas Services, LP, accounted for approximately 13% of our 2010 operating revenues. Refer to Item 1A, *Risk Factors*, regarding risks associated with our customers.

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 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 200 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.

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.

Power Generators. The power generation market is a growing source of demand for natural gas. We have the ability to serve more than 45 natural gas-fired power generation facilities in ten states. We are directly connected to 38 of these facilities. 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.

Industrial End Users. We provide approximately 160 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 other pipelines to maintain current business levels and to serve new demand and markets. We also compete with other pipelines for contracts with producers that would support new growth opportunities for us. The principal elements of competition among pipelines are available capacity, rates, terms of service, access to gas supplies, flexibility and reliability of service. Due to the construction of new pipeline systems in the U.S. over the past several years, as well as pipelines currently under development, competition has become stronger in our market areas. Many of these new pipelines are in areas outside our service area and are closer to end users than our pipeline systems. 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. Additionally, natural gas competes with other forms of energy available to our customers, including electricity, coal, fuel oils and other alternative fuel sources.

The new pipeline infrastructure mentioned above is supporting the development across the U.S. of unconventional natural gas supply basins such as gas shales and tight sand formations. The new sources of natural gas 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, in 2009 the price differentials between physical locations (basis spreads) on our pipeline systems began to narrow. This trend continued into 2010. Basis spreads have impacted, and will continue to impact, the rates we have been able to negotiate with our customers on contracts due for renewal for our firm transportation services, as well as the rates we are able to charge for our interruptible and short-term firm transportation services. Capacity that we have available on a short-term basis has decreased as long-term capacity commitments on our recently completed pipeline expansion projects have increased in accordance with the contracts supporting those projects. However, some of our capacity will continue to be available for sale on a short-term firm or interruptible basis and each year a portion of our existing contracts expire. The revenues we will be able to earn from that available capacity and from renewals of expiring contracts will be heavily dependent upon basis spreads. It is not possible to accurately predict future basis spreads.

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 over time. During 2010, approximately 54% of our revenue was 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. Gulf Crossing has an obligation to file either a rate case or a cost-and-revenue study by the end of the first quarter 2012 to justify its rates.

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 the 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.

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, which we will be required to report to the Environmental Protection Agency (EPA) beginning in 2011;

- 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, 2010, we had approximately 1,100 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. There may be additional risks that we do not yet know of or that we do not currently perceive to be material that may also impact our business or the business of our subsidiaries.

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, in 2009 basis spreads on our pipeline systems began to narrow. Basis spreads have impacted, and will continue to impact, the rates we have been able to negotiate with our customers or contracts due for renewal for our firm transportation services, as well as the rates we are able to charge for our interruptible and short-term firm transportation services.

The principal elements of competition among pipelines are availability of capacity, rates, terms of service, access to gas supplies, flexibility and reliability of service. 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 our 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.

Continued development of new supply sources could impact 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 markets 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, Canada and LNG import terminals 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 13% of our 2010 revenues and we expect this customer to continue to account for more than 10% of our 2011 revenues. Our top ten customers comprised approximately 45% of our revenues in 2010. 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 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 pursue complex pipeline or storage projects which involve significant risks.

The most significant element of our growth strategy in recent years was the completion of large development projects to enlarge and enhance our pipeline and storage systems. We may undertake additional large development projects in the future as we continue to pursue our growth strategy. 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.

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.

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 Caney 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.

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

Our revolving credit agreement 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. While neither Gulf South nor Texas Gas has an obligation to file a rate case, Gulf Crossing has an obligation to file either a rate case or a cost-and-revenue study by the end of the first quarter 2012 to justify its rates. Customers or FERC can challenge the existing rates on any of our pipelines. During the past two years, FERC has challenged the rates of several pipelines not affiliated with us. 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 may not be able to recover all of our costs through existing or future rates.

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 2010, there were 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 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. Beginning in 2011, we will be required to file reports with the EPA regarding greenhouse gas emissions from our facilities, mainly 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. 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 already 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 66% 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. Reserved

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, 2010, we had outstanding 169.7 million common units, 22.9 million class B units, a 2% general partner interest and IDRs. 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. The common units, class B units and general partner interest held by BPHC represent approximately 66% 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 16, 2011, we had 169.7 million common units outstanding held by approximately 60 holders of record. BPHC owns 102.7 million of our common units and all of our class B units, for which there is no established public trading market. 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 16, 2011, was $32.84 per unit.

	Sales Price Range per Common Unit		Cash Distributions per Common Unit (1) (2)
	High	Low	
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**
Year ended December 31, 2009:			
Fourth quarter	$ 30.77	$ 24.01	$ 0.500
Third quarter	25.30	21.85	0.495
Second quarter	23.67	19.43	0.490
First quarter	23.67	17.82	0.485

(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 2010, 2009 and 2008, we paid $18.2 million, $13.3 million and $7.5 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	
	Target Amount	Limited Partner Unitholders (1)	General Partner
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 and 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 (4) *Non-GAAP Financial Measures* below. 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 and Net income per subordinated unit. Distributions per common unit and Distributions per Class B unit):

	For the Year Ended December 31,				
	2010	2009	2008	2007	2006
Total operating revenues	**$ 1,116.8**	$ 909.2	$ 784.8	$ 643.2	$ 607.6
Net income	**289.4**	162.7	294.0	227.7	197.6
Total assets	**6,878.0**	6,895.8	6,721.6	4,122.0	2,909.2
Long-term debt	**3,252.3**	3,100.0	2,889.4	1,847.9	1,350.9
Net income per common unit	**1.47**	0.88	2.09	1.91	1.90
Net income per class B unit (1)	**0.62**	0.08	0.60	-	-
Net income per subordinated unit (1)	**-**	-	1.68	1.86	1.88
Distributions per common unit (2)	**2.03**	1.95	1.87	1.74	1.32 (3)
Distributions per class B unit (1)	**1.20**	1.20	0.30	-	-
EBITDA (4)	**658.2**	498.0	474.6	349.8	331.5
Distributable cash flow (4)	**448.5**	314.3	382.3	253.6	231.1

(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, 2006 through 2008.

(3) The distribution paid in the first quarter 2006 represented a prorated portion of the $0.35 per unit "minimum quarterly distribution" (as defined in our partnership agreement) for the period November 15, 2005 through December 31, 2005.

(4) 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,				
	2010	2009	2008	2007	2006
Net income	**$ 289.4**	$ 162.7	$ 294.0	$ 227.7	$ 197.6
Income taxes	**0.5**	0.3	1.0	0.8	0.2
Depreciation and amortization	**217.9**	203.1	124.8	81.8	75.8
Interest expense	**151.0**	132.1	57.7	61.0	62.1
Interest income	**(0.6)**	(0.2)	(2.9)	(21.5)	(4.2)
EBITDA	**658.2**	$ 498.0	$ 474.6	$ 349.8	$ 331.5
Less:					
Cash paid for interest	**146.3**	124.4	42.8	46.1	57.5
Maintenance capital expenditures	**63.0**	58.9	50.5	47.1	41.7
Other (1)	**0.4**	0.4	(1.0)	3.0	1.2
Distributable Cash Flow	**$ 448.5**	$ 314.3	$ 382.3	$ 253.6	$ 231.1

(1) Includes non-cash items such as the equity component of allowance for funds used during construction.

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

Overview

Through our operating subsidiaries, Gulf Crossing Pipeline Company LLC (Gulf Crossing), Gulf South Pipeline Company, LP (Gulf South) and Texas Gas Transmission, LLC (Texas Gas), 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 2010, our pipeline systems transported approximately 2.5 Tcf of gas. Average daily throughput on our pipeline systems during 2010 was approximately 6.8 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 parking and lending (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. 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.

Competition and Contract Renewals

Our ability to market available interstate transportation and storage capacity is impacted by demand for natural gas, competition from other pipelines, natural gas price volatility, basis spreads, economic conditions and other factors. We compete with numerous interstate and intrastate pipelines, including several pipeline projects which have recently been placed in service or are in the process of being developed. Additionally, significant new sources of natural gas have recently been identified throughout the U.S., including the Marcellus Shale in Pennsylvania, New York, West Virginia and Ohio, which are closer to key end-user market areas than our supply sources. These new sources of natural gas 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, in 2009 the basis spreads on our pipeline systems began to narrow. This trend continued into 2010, although in the latter part of 2010 basis spreads on our pipeline systems improved.

Under current market conditions, marketing our available capacity and renewing expiring contracts have become more difficult. Our ability to renew some of our expiring contracts at attractive rates and our revenues from interruptible and short-term firm transportation services have been negatively impacted by these market conditions. Capacity that we have available on a short-term basis has decreased as long-term capacity commitments on our recently completed pipeline expansion projects have increased in accordance with the contracts supporting those projects. However, some of our capacity will continue to be available for sale on a short-term firm or interruptible basis and each year a portion of our existing contracts expire. The revenues we will be able to earn from that available capacity and from renewals of expiring contracts will be heavily dependent upon basis spreads. It is not possible to accurately predict future basis spreads.

Regulation

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. While neither Gulf South nor Texas Gas has an obligation to file a rate case, our Gulf Crossing pipeline has an obligation to file either a rate case or a cost-and-revenue study by the end of the first quarter 2012 to justify its rates. Customers of our subsidiaries or FERC can challenge the existing rates on any of our pipelines. In the past two years, FERC has challenged the rates of several pipelines not affiliated with us. Such a challenge 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. Additionally, FERC can propose changes or modifications to any of its existing rate-related policies.

We are also subject to pipeline integrity programs monitored by PHMSA. In 2010, there were several integrity-related incidents on pipelines not affiliated with us that could lead to increased regulation of natural gas pipelines by PHMSA. The potential for increased regulation regarding pipeline integrity could lead to increased capital spending and maintenance costs.

Natural Gas Prices

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. 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.

The majority of our revenues are derived from capacity reservation charges that are not impacted by the volume of natural gas transported, however smaller portions of our revenues are derived from charges based on actual volumes transported under firm and interruptible services. For example, in 2010 approximately 22% of our revenues were derived from charges based on actual volumes transported. We cannot predict the level of future natural gas prices.

Spreads in natural gas prices between time periods, such as winter to summer, impact our PAL and interruptible storage revenues. These price spreads were unfavorable in 2010 as compared with 2009 resulting in a reduction of our PAL and interruptible storage revenues for the 2010 period. We cannot predict future time period spreads or basis differentials.

Recently Completed Pipeline Projects

An abundance of recent natural gas supply discoveries in the Bossier Sands, Barnett Shale, Haynesville Shale, Fayetteville Shale and Caney Woodford Shale producing regions has formed the basis for the recent expansion of our pipeline systems. In 2008 and 2009, we placed in service our East Texas Pipeline, Southeast Project, Gulf Crossing Pipeline and the Fayetteville and Greenville Laterals (pipeline expansion projects), which collectively consist of approximately 1,000 miles of 42-inch and 36-inch pipeline and related compression facilities. In 2010, we placed in service the remaining compression facilities associated with the Gulf Crossing Pipeline and the Fayetteville and Greenville Laterals which increased the peak-day delivery capacities of those projects. With the exception of post-construction activities such as right-of-way restoration, the pipeline expansion projects are essentially complete and operating at their design capacity.

Financial Analysis of Operations

We derive our revenues primarily from the interstate transportation and storage of natural gas for third parties. Transportation and storage services are provided under firm and interruptible service agreements. 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. The following analysis discusses our financial results of operations for the years 2010, 2009 and 2008.

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.

2009 Compared with 2008

Our net income for the year ended December 31, 2009, decreased $131.3 million, or 45%, to $162.7 million compared to $294.0 million for the year ended December 31, 2008. Operating expenses for the year ended December 31, 2009, were higher than the comparable period in 2008, mainly as a result of increases in depreciation and property taxes associated with our pipeline expansion projects. The increase in expenses more than offset the increase in revenues from our pipeline expansion projects, which were approximately $122.0 million lower than expected 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 during 2009. The 2008 period was favorably impacted by $62.5 million of gains from the disposition of coal reserves, gas sales associated with our storage expansion and the settlement of a contract claim.

Operating revenues for the year ended December 31, 2009, increased $124.4 million, or 16%, to $909.2 million, compared to $784.8 million for the year ended December 31, 2008. Gas transportation revenues, excluding fuel, increased $152.4 million, primarily from our pipeline expansion projects. PAL revenues increased $18.6 million due to increased parking opportunities and favorable summer-to-summer natural gas price spreads. The increases were partially offset by lower fuel revenues of $52.7 million due to unfavorable natural gas prices.

Operating costs and expenses for the year ended December 31, 2009, increased $176.5 million, or 40%, to $614.7 million, compared to $438.2 million for the year ended December 31, 2008. The primary factors for the increases were higher depreciation and property taxes of $115.5 million associated with a larger asset base from our pipeline expansion projects. Operation and maintenance expenses increased approximately $13.4 million primarily from increased maintenance projects and expansion-related operations. Administrative and general expenses increased $10.8 million mainly due to increases in employee benefits as a result of lower returns on trust assets for our pension and post-retirement benefit plans and increases in unit-based compensation from an increase in the price of our common units. Operation and maintenance expenses and losses on disposal of assets were $7.5 million higher due to pipeline investigation and retirement costs related to the East Texas Pipeline. Fuel and gas transportation expenses decreased $40.5 million primarily as a result of lower natural gas prices. The 2008 period was favorably impacted by gains of $34.8 million on the sale of gas related to our Western Kentucky Storage Expansion project, $16.5 million from the disposition of coal reserves, $11.2 million from the settlement of a contract claim and $6.5 million due to a change in employee paid time off policy which resulted in a reserve reversal.

Total other deductions increased by $79.9 million, or 155%, to $131.5 million for the year ended December 31, 2009, compared to $51.6 million for the 2008 period. The primary factor for the increase was higher interest expense of $74.4 million resulting from lower capitalized interest associated with placing expansion projects in service and higher debt levels in 2009.

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.

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 cash flow generated from future operations will be adequate to fund our operations, including our capital expenditures for maintenance and growth projects.

Capital Expenditures

Maintenance capital expenditures for the years ended December 31, 2010, 2009 and 2008 were $63.0 million $58.9 million and $50.5 million. Growth capital expenditures, including costs associated with our pipeline expansion projects, were $160.7 million, $754.2 million and $2.6 billion for the years ended December 31, 2010, 2009 and 2008. We expect to fund our 2011 capital expenditures of less than $160.0 million from our operating cash flows or, if necessary, borrowings under our revolving credit facility.

Equity and Debt Financing

In 2010, we did not enter into any new equity or debt financing transactions. In January 2011, we received net proceeds of approximately $322.2 million after deducting initial purchaser discounts and offering expenses of $2.8 million from the sale of $325.0 million of 4.50% senior unsecured notes of Texas Gas due February 1, 2021 (2021 Notes). We used these proceeds to repay borrowings under our revolving credit facility. In January 2011, we notified the holders of Texas Gas' 5.5% notes due April 1, 2013 (2013 Notes) that we will redeem $135.0 million of those notes in February 2011 at the redemption price provided for in the indenture governing such notes. We will borrow funds under our revolving credit facility to fund this redemption. Note 7 in Item 8 of this report contains more information about the 2021 Notes and partial redemption of the 2013 Notes.

We anticipate the need to issue and sell debt during the next several years to refinance outstanding debt and our revolving credit facility either prior to or at their maturities. See *Contractual Obligations* for a summary of the amounts and timing of our debt maturities.

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, 2010, we had $703.5 million of loans outstanding under our revolving credit facility with a weighted-average interest rate of 0.53% and no letters of credit issued thereunder. As a result of the issuance of the 2021 Notes discussed above, borrowings under our revolving credit facility were reduced by $320.0 million and at February 18, 2011, we had $383.5 million in loans outstanding under our revolving credit facility with a weighted-average interest rate of 0.52%. At such date we had available borrowing capacity of $566.5 million. As discussed above, in February 2011, we will borrow funds under this facility to pay the redemption price for $135.0 million of 2013 Notes.

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, 2010. 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, 2010, 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)	$ 3,263.5	$ -	$ 1,278.5	$ 525.0	$ 1,460.0
Interest on long-term debt (2)	883.6	145.6	262.7	209.2	266.1
Capital commitments (3)	30.8	30.8	-	-	-
Pipeline capacity agreements (4)	58.2	9.8	17.7	16.0	14.7
Operating lease commitments	21.5	4.0	7.2	5.8	4.5
Total	$ 4,257.6	$ 190.2	$ 1,566.1	$ 756.0	$ 1,745.3

(1) Includes our senior unsecured notes, having maturity dates from 2012 to 2027, $703.5 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. The revolving credit facility and Subordinated Loans are extendable by us on the same terms for an additional year. Subsequent to December 31, 2010, we issued and sold additional debt as discussed under *Equity and Debt Financing*.

(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 0.53% weighted-average interest rate on amounts outstanding under our revolving credit facility as of December 31, 2010, $3.7 million and $1.8 million would be due under the credit facility in less than one year and 1-3 years. Subsequent to December 31, 2010, borrowings under the revolving credit facility were reduced as discussed under *Revolving Credit Facility*.

(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, 2010.

(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 2011, we expect to fund approximately $8.8 million to the Texas Gas pension plan.

Distributions

For the twelve months ended December 31, 2010, 2009 and 2008, we paid distributions of $398.1 million, $360.6 million and $260.5 million to our partners. Note 10 in Part II, Item 8 of this report contains further discussion regarding our distributions.

Changes in cash flow from operating activities

Net cash provided by operating activities increased $64.2 million to $464.7 million for the year ended December 31, 2010, compared to $400.5 million for the comparable 2009 period, primarily due to an increase in net income, partly offset from lower prepayments received under PAL and transportation agreements.

Changes in cash flow from investing activities

Net cash used in investing activities decreased $475.4 million to $196.4 million for the year ended December 31, 2010, compared to $671.8 million for the comparable 2009 period. The decrease was driven by a $619.5 million decrease in capital expenditures primarily related to the completion of our pipeline expansion projects and $30.9 million in proceeds from the sale of assets, mainly comprised of storage gas sales. The decreases were partially offset by the sale of $175.0 million of short-term investments which occurred in the 2009 period.

Changes in cash flow from financing activities

Net cash used in financing activities increased $438.5 million to a use of cash of $259.1 million for the year ended December 31, 2010, compared to cash provided by financing activities of $179.4 million for the comparable 2009 period. The increase in cash used in financing activities resulted from a $779.8 million reduction in proceeds from the issuance and sale of debt and equity, including related general partner contributions, a $37.5 million increase in distributions to our partners and $10.7 million of payments made under our registration rights agreement. The increases were partly offset by a decrease of $388.5 million in net repayments related to our revolving credit facility.

Impact of Inflation

We have experienced increased costs in recent years due to the effect of inflation on the cost of labor, benefits, materials and supplies, and property, plant and equipment (PPE). A portion of the increased labor and materials and supplies costs have directly affected income through increased operating costs and depreciation expense. 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 PPE 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, 2010, 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

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, 2010 and 2009, 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 will either have to file a rate case or justify its initial firm transportation rates by the end of the first quarter 2012.

Our subsidiaries are regulated by 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 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 and the settlement history.

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.

We have included fair value measurements in our disclosures regarding the fair value of our debt and the trust assets associated with our pension and postretirement benefits plans, as well as to determine the fair value of Texas Gas for purposes of completing our annual impairment test for goodwill. The amounts disclosed for the fair value of our debt and benefit plan trust assets were based on quoted market prices for those assets or similar assets, however at December 31, 2010, approximately $39.5 million of the benefits plan trust assets were based on unobservable data inputs. For the 2010 annual test, the fair value measurement associated with our goodwill impairment test was derived based on our assumptions we believe market participants would use in pricing the reporting unit, including the use of a discounted cash flow model, which are generally unobservable data inputs under the fair value hierarchy. Please refer to *Goodwill* for more information regarding the annual test and judgments and assumptions used in completing the test. Our Consolidated Financial Statements include fair value measurements related to derivatives. At December 31, 2010, the fair value of our derivatives was determined based on quoted market prices for similar contracts. Notes 2, 5, 8, 9 and 12 in Item 8 of this Report 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, 2010, we had accrued approximately $11.2 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 value of long-lived assets has been impaired when circumstances indicate the carrying value 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 value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value. Note 4 in Item 8 of this Report contains more information regarding impairments we have recognized.

Goodwill

As of December 31, 2010, we had $163.5 million of goodwill recorded as an asset on our Consolidated Balance Sheets which was initially recorded in conjunction with the acquisition of our Texas Gas subsidiary. In accordance with GAAP, we are required to evaluate goodwill for impairment at least annually or more frequently if events and circumstances indicate that the asset might be impaired. For purposes of a goodwill impairment test, the reporting unit's fair value is determined in accordance with accounting requirements involving fair value measurements as described under *Fair Value Measurements*. We perform this test annually at December 31.

For the 2010 annual goodwill impairment test, the fair value measurement of the reporting unit associated with our goodwill was derived based on judgments and assumptions we believe market participants would use in pricing the reporting unit, which are generally unobservable data inputs under the fair value hierarchy. These judgments and assumptions included the valuation premise, use of a discounted cash flow model to estimate fair value and inputs to the valuation model. The inputs included our five-year financial plan operating results, the long-term outlook for growth in natural gas demand in the U.S. and measures of the risk-free rate, equity premium and systematic risk used in the calculation of the applied discount rate under the capital asset pricing model. The resulting estimate of fair value was compared to the carrying amount of the reporting unit, including goodwill. The estimated fair value was significantly in excess of the carrying amount at December 31, 2010, and accordingly no impairment was recognized. The use of alternate judgments and/or assumptions could substantially change the fair value determined during the annual test 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 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 pension obligations and pension expense.

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 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 PHMSA, on our business, including our costs, liabilities and revenues;
- the timing, cost, scope and financial performance of our recent and future growth projects;
- volatility or disruptions in the capital or financial markets;
- the impact of FERC 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; 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):

	2010	2009
Carrying value of fixed-rate debt	**$ 2,548.8**	$ 2,546.5
Fair value of fixed-rate debt	**$ 2,717.0**	$ 2,615.1
100 basis point increase in interest rates and resulting debt decrease	**$ 126.0**	$ 130.7
100 basis point decrease in interest rates and resulting debt increase	**$ 126.5**	$ 140.3
Weighted-average interest rate, including Subordinated Loan	**5.97%**	5.97%

At December 31, 2010, we had $703.5 million outstanding under our revolving credit agreement at a weighted-average interest rate of 0.53% which rate is reset periodically. A 1% increase in interest rates would increase our cash payments for interest on the credit facility by $7.0 million on an annual basis. At December 31, 2009, we had $553.5 million outstanding under our revolving credit facility at a weighted-average interest rate of 0.48%.

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. In January 2011, we mitigated a portion of that risk through the issuance and sale of $325.0 million of 2021 Notes. We used the net proceeds from the 2021 Notes to pay down amounts borrowed under our revolving credit facility. We also issued a notice to holders of 2013 Notes that we will redeem $135.0 million of those notes. We will borrow against our revolving credit facility to fund the redemption. After the redemption of the 2013 Notes, we will have reduced borrowings under our revolving credit facility by $185.0 million, which will reduce the amount of debt subject to variable interest rates and will have refinanced a portion of our fixed rate debt which was set to mature within three years. 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, 2010 and 2009, $55.0 million and $45.8 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, 2010 and 2009, approximately $3.6 million and $2.3 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, we have 4.5 Bcf of gas with a book value of $8.8 million that has become available for sale as a result of a change in storage gas needed to support operations and no-notice services. We utilize derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas.

The derivatives related to the sale of natural gas and cash for fuel reimbursement where customers make a cash payment for the estimated cost of fuel used in providing transportation services as opposed to providing quantities of natural gas, generally qualify for cash flow hedge accounting and are designated as such. The effective component of related 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 or loss. The deferred gains and losses are recognized in earnings when the anticipated transactions affect earnings. Generally, for gas sales and retained fuel, any gains and losses on the related derivatives would be recognized in operating revenues, or as they relate to the sale of storage gas, in *Net (gain)/loss on disposal of operating assets*.

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.

We compete with numerous interstate and intrastate pipelines, including several pipeline projects which have recently been placed in service or are in the process of being developed. Additionally, significant new sources of natural gas have recently been identified throughout the U.S. which 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, in 2009 basis spreads on our pipeline systems began to narrow. This trend continued into 2010 although in the latter part of 2010, basis spreads on our pipeline systems improved.

Under current market conditions, marketing our available capacity and renewing expiring contracts have become difficult. Our ability to renew some of our expiring contracts at attractive rates, and our revenues from interruptible and short-term firm transportation services, have been negatively impacted by these market conditions. Capacity that we have available on a short-term basis has decreased as long-term capacity commitments on our recently completed pipeline expansion projects have increased in accordance with the contracts supporting those projects. However, some of our capacity will continue to be available for sale on a short-term firm or interruptible basis and each year a portion of our existing contracts expire. The revenues we will be able to earn from that available capacity and from renewals of expiring contracts will be heavily dependent upon basis spreads. It is not possible to accurately predict future basis spreads.

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, 2010, the amount of gas loaned out by our subsidiaries or owed to our subsidiaries due to gas imbalances was approximately 13.0 trillion British thermal units (TBtu). Assuming an average market price during December 2010 of $4.21 per million British thermal units (MMBtu), the market value of that gas was approximately $54.7 million. As of December 31, 2009, the amount of gas loaned out by our subsidiaries or owed to our subsidiaries due to gas imbalances was approximately 14.9 TBtu. Assuming an average market price during December 2009 of $5.36 per MMBtu, the market value of this gas at December 31, 2009, would have been approximately $79.9 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, 2010 and 2009, 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, 2010. 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. 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, 2010, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 18, 2011, expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ Deloitte & Touche LLP
Houston, Texas
February 18, 2011

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED BALANCE SHEETS
(Millions)

ASSETS	December 31, 2010	December 31, 2009
Current Assets:		
Cash and cash equivalents	**$ 55.0**	$ 45.8
Receivables:		
Trade, net	**101.0**	95.5
Other	**5.2**	13.5
Gas transportation receivables	**12.2**	7.9
Costs recoverable from customers	**11.3**	6.0
Gas stored underground	**3.6**	2.1
Prepayments	**11.4**	10.1
Other current assets	**3.5**	10.0
Total current assets	**203.2**	190.9
Property, Plant and Equipment:		
Natural gas transmission and other plant	**6,933.9**	6,623.8
Construction work in progress	**109.9**	231.4
Property, plant and equipment, gross	**7,043.8**	6,855.2
Less—accumulated depreciation and amortization	**785.8**	577.3
Property, plant and equipment, net	**6,258.0**	6,277.9
Other Assets:		
Goodwill	**163.5**	163.5
Gas stored underground	**125.8**	133.7
Costs recoverable from customers	**15.7**	16.1
Other	**111.8**	113.7
Total other assets	**416.8**	427.0
Total Assets	**$ 6,878.0**	$ 6,895.8

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, 2010	December 31, 2009
Current Liabilities:		
Payables:		
Trade	**$ 48.8**	$ 58.4
Affiliates	**3.2**	8.6
Other	**10.1**	17.8
Gas Payables:		
Transportation	**20.5**	5.0
Storage	**4.2**	-
Accrued taxes, other	**40.4**	41.2
Accrued interest	**40.5**	41.8
Accrued payroll and employee benefits	**17.0**	16.4
Construction retainage	**8.3**	21.0
Deferred income	**6.3**	20.9
Other current liabilities	**14.5**	19.8
Total current liabilities	**213.8**	250.9
Long–term debt	**3,152.3**	3,000.0
Long–term debt – affiliate	**100.0**	100.0
Total long-term debt	**3,252.3**	3,100.0
Other Liabilities and Deferred Credits:		
Pension liability	**27.0**	31.6
Asset retirement obligation	**17.2**	18.0
Provision for other asset retirement	**51.7**	47.0
Payable to affiliate	**16.0**	20.6
Other	**58.6**	63.5
Total other liabilities and deferred credits	**170.5**	180.7
Commitments and Contingencies		
Partners' Capital:		
Common units – 169.7 million units issued and outstanding as of December 31, 2010, and December 31, 2009	**2,534.4**	2,640.5
Class B units – 22.9 million units issued and outstanding as of December 31, 2010, and December 31, 2009	**683.6**	683.6
General partner	**62.9**	65.5
Accumulated other comprehensive loss	**(39.5)**	(25.4)
Total partners' capital	**3,241.4**	3,364.2
Total Liabilities and Partners' Capital	**$ 6,878.0**	$ 6,895.8

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,		
	2010	2009	2008
Operating Revenues:			
Gas transportation	**$ 1,015.4**	$ 794.9	$ 698.2
Parking and lending	**28.1**	34.9	16.3
Gas storage	**55.4**	57.6	51.5
Other	**17.9**	21.8	18.8
Total operating revenues	**1,116.8**	909.2	784.8
Operating Costs and Expenses:			
Fuel and gas transportation	**109.4**	61.9	102.4
Operation and maintenance	**149.6**	142.2	119.9
Administrative and general	**126.6**	122.0	106.0
Depreciation and amortization	**217.9**	203.1	124.8
Contract settlement gain	**-**	-	(11.2)
Asset impairment	**5.8**	-	3.0
Net (gain) loss on disposal of operating assets	**(16.6)**	8.2	(49.2)
Taxes other than income taxes	**84.2**	77.3	42.5
Total operating costs and expenses	**676.9**	614.7	438.2
Operating income	**439.9**	294.5	346.6
Other Deductions (Income):			
Interest expense	**142.9**	125.3	57.7
Interest expense – affiliates	**8.1**	6.8	-
Interest income	**(0.6)**	(0.2)	(2.9)
Miscellaneous other income, net	**(0.4)**	(0.4)	(3.2)
Total other deductions	**150.0**	131.5	51.6
Income before income taxes	**289.9**	163.0	295.0
Income taxes (benefit)	**0.5**	0.3	1.0
Net Income	**$ 289.4**	$ 162.7	$ 294.0
Net Income per Unit:			
Basic and diluted net income per unit:			
Common units (1)	**$ 1.47**	$ 0.88	$ 2.09
Class B units	**$ 0.62**	$ 0.08	$ 0.60
Subordinated units (1)	**$ -**	$ -	$ 1.68
Cash distribution to common units and subordinated unitholders (1)	**$ 2.03**	$ 1.95	$ 1.87
Cash distribution to class B units	**$ 1.20**	$ 1.20	$ 0.30
Weighted-average number of units outstanding:			
Common units (1)	**169.7**	161.6	104.2
Class B units (2)	**22.9**	22.9	22.9
Subordinated units (1)	**-**	-	28.7

(1) All of the 33.1 million subordinated units converted to common units on a one-for-one basis in November 2008.
(2) Number of class B units shown is weighted from July 1, 2008, which is the date they became eligible to participate in earnings. The class B units do not participate in quarterly distributions above $0.30 per unit.

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,		
OPERATING ACTIVITIES:	**2010**	2009	2008
Net income	**$ 289.4**	$ 162.7	$ 294.0
Adjustments to reconcile to cash provided by operations:			
Depreciation and amortization	**217.9**	203.1	124.8
Amortization of deferred costs	**8.1**	9.4	9.0
Amortization of acquired executory contracts	**-**	-	(0.2)
Asset impairment	**5.8**	-	3.0
Net (gain) loss on disposal of operating assets	**(16.6)**	8.2	(49.2)
Changes in operating assets and liabilities:			
Trade and other receivables	**(9.7)**	(23.4)	(16.6)
Gas receivables and storage assets	**(10.5)**	(5.0)	26.2
Costs recoverable from customers	**(5.4)**	(1.6)	0.9
Inventories	**-**	-	(8.8)
Other assets	**23.1**	(18.0)	(30.5)
Trade and other payables	**(27.4)**	25.9	9.5
Other payables, affiliates	**0.7**	0.7	-
Gas payables	**10.0**	2.4	(15.1)
Accrued liabilities	**0.9**	4.3	7.0
Other liabilities	**(21.6)**	31.8	(3.7)
Net cash provided by operating activities	**464.7**	400.5	350.3
INVESTING ACTIVITIES:			
Capital expenditures	**(227.3)**	(846.8)	(2,652.5)
Proceeds from sale of operating assets	**30.9**	-	63.8
Proceeds from insurance reimbursements and other recoveries	**-**	-	4.7
Advances to affiliates, net	**-**	-	1.6
Sales (purchases) of short-term investments	**-**	175.0	(175.0)
Net cash used in investing activities	**(196.4)**	(671.8)	(2,757.4)
FINANCING ACTIVITIES:			
Proceeds from long-term debt, net of issuance costs	**-**	346.7	247.2
Proceeds from borrowings on revolving credit agreement	**175.0**	411.5	1,484.0
Repayment of borrowings on revolving credit agreement	**(25.0)**	(650.0)	(692.0)
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	**(398.1)**	(360.6)	(260.5)
Proceeds from sale of common units	**-**	326.3	733.6
Proceeds from sale of class B units	**-**	-	686.0
Capital contribution from general partner	**-**	6.8	29.2
Net cash (used in) provided by financing activities	**(259.1)**	179.4	2,227.5
Increase (decrease) in cash and cash equivalents	**9.2**	(91.9)	(179.6)
Cash and cash equivalents at beginning of period	**45.8**	137.7	317.3
Cash and cash equivalents at end of period	**$ 55.0**	$ 45.8	$ 137.7

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	Subordinated Units	General Partner	Accumulated Other Comp Income (Loss)	Total Partners' Capital
Balance January 1, 2008	$ 1,473.9	$ -	$ 291.7	$ 33.2	$ 4.2	$ 1,803.0
Add (deduct):						
Net income	207.4	13.7	59.7	13.2	-	294.0
Distributions paid	(179.0)	(6.9)	(61.9)	(12.7)	-	(260.5)
Sale of common units, net of related transaction costs	713.0	-	-	-	-	713.0
Sale of class B units	-	686.0	-	-	-	686.0
Conversion of subordinated units to common units	289.5	-	(289.5)	-	-	-
Capital contribution from general partner	-	-	-	29.2	-	29.2
Other comprehensive loss, net of tax	-	-	-	-	(19.7)	(19.7)
Balance December 31, 2008	$ 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**

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,		
	2010	2009	2008
Net income	**$ 289.4**	$ 162.7	$ 294.0
Other comprehensive income (loss):			
Gain (loss) on cash flow hedges	**6.0**	10.5	(16.7)
Reclassification adjustment transferred to Net income from cash flow hedges	**(13.0)**	(16.5)	24.9
Pension and other postretirement benefit costs	**(7.1)**	(3.9)	(27.9)
Total Comprehensive Income	**$ 275.3**	$ 152.8	$ 274.3

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 to own and operate the business conducted by its 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). As of December 31, 2010, 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). The common units, class B units and general partner interest owned by BPHC represent approximately 66% 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, Boardwalk Pipelines, Gulf Crossing, Gulf South and Texas Gas, after elimination of intercompany transactions.

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, including the Partnership's debt and pension and postretirement benefits trust assets. On an ongoing basis, the Partnership evaluates its estimates, including but not limited to those related to bad debts, goodwill, property and equipment and other long-lived assets, property taxes, pensions and other postretirement and postemployment benefits, share-based and other incentive compensation, contingent liabilities, revenues subject to refund and fair value. The Partnership bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values 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, 2010 and 2009.

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 82.9 trillion British thermal units (TBtu) of gas owned by third parties as of December 31, 2010. Assuming an average market price during December 2010 of $4.21 per million British thermal units (MMBtu), the market value of gas held on behalf of others was approximately $349.0 million. As of December 31, 2009, the Partnership held for storage or under PAL agreements approximately 84.7 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.

Inventories

Inventories consisting of materials and supplies are carried at average cost. The Partnership expects its materials and supplies inventories to be used for capital projects related to its property, plant and equipment and includes the inventories in *Other Assets*.

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 value 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 value 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 value 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,		
	2010	2009	2008
Capitalized interest and allowance for borrowed funds used during construction	$ **4.2**	$ 10.3	$ 71.1
Allowance for equity funds used during construction	**0.4**	0.4	0.2

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, 2010 and 2009, the Partnership had deferred revenues of $5.6 million and $21.3 million related to PAL and interruptible storage services and $7.4 million and $8.3 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 2011 and 2012 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, 2010, 2009 and 2008 was $114.2 million, $77.5 million and $134.9 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, 2010 and 2009, 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 to certain employees awards of unit appreciation rights (UARs) and long-term cash bonuses (Long-Term Cash Bonuses) under its Unit Appreciation Rights and Cash Bonus Plan, which was established in 2010. The Partnership previously provided awards of phantom units to certain employees under its Long-Term Incentive Plan and Strategic Long-Term Incentive Plan. 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. These awards are payable only in cash and are classified as a liability until the time of 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

Subsidiaries of 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. 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 includes fair value measurements in its disclosures regarding the fair value of its debt and trust assets associated with its pension and postretirement benefits plans, and in performing its annual impairment test for goodwill. The Partnership's financial statements include fair value measurements related to derivatives. The fair value of the Partnership's derivatives is determined based on quoted market prices for similar contracts. Notes 5, 8, 9 and 12 and *Goodwill* contain more information regarding the Partnership's fair value measurements.

Goodwill

In accordance with GAAP, the Partnership is required to evaluate its goodwill for impairment at least annually or more frequently if events and circumstances indicate that the asset might be impaired. For purposes of a goodwill impairment test, the reporting unit's fair value is determined in accordance with accounting requirements involving fair value measurements as described under *Fair Value Measurements*. The impairment test for goodwill is performed annually at December 31.

For the 2010 annual goodwill impairment test, the fair value measurement of the reporting unit associated with the Partnership's goodwill was derived based on assumptions the Partnership believes market participants would use in pricing the reporting unit, which are generally unobservable data inputs under the fair value hierarchy. These judgments and assumptions included the valuation premise, use of a discounted cash flow model to estimate fair value and inputs to the valuation model. The inputs included the Partnership's five-year financial plan operating results, the long-term outlook for growth in natural gas demand in the United States (U.S.) and measures of the risk-free rate, equity premium and systematic risk used in the calculation of the applied discount rate under the capital asset pricing model. The resulting estimate of fair value was compared to the carrying amount of the reporting unit, including goodwill. The estimated fair value was significantly in excess of the carrying amount at December 31, 2010, and accordingly no impairment was recognized. Similarly, no impairment of goodwill was recorded during 2009 or 2008.

Note 3: Commitments and Contingencies

Legal Proceedings and Settlements

Napoleonville Salt Dome Matter

Following the December 2003 accidental release of natural gas from storage in a salt dome cavern operated by Gulf South at the Dow Hydrocarbon and Resources, Inc. (Dow Hydrocarbon), Grand Bayou facility in Belle Rose, Louisiana, several suits were filed. All of the litigation surrounding this incident has been resolved. The resolution of these cases did not have a material financial effect on the Partnership.

Other Legal Matters

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 adverse impact on the Partnership's financial condition, results of operations or cash flows.

Calpine Energy Services (Calpine) Settlement

In 2008, the Partnership received a cash payment of approximately $15.3 million as settlement of a claim against Calpine and recorded a net gain of $11.2 million related to the realization of the unrecognized portion of the claim, which was reported as *Contract settlement gain* on the Consolidated Statements of Income.

Contractual Release

In 2008, the Partnership received notice of dissolution of the Alaskan Northwest Natural Gas Transportation Company which was formed in the 1970s and in which Texas Gas was an inactive investor. Along with the notice of dissolution, Texas Gas received a full release from any obligations associated with its equity method investment. As a result, the Partnership reversed the remainder of its liability for estimated obligations associated with the investment and recognized income of $3.3 million in *Miscellaneous other income*, *net* on the Consolidated Statements of Income. The book value of the investment was zero at December 31, 2008.

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. The Partnership accrues for environmental expenses resulting from existing conditions that relate to past operations when the costs are probable and can be reasonably estimated. In addition to federal and state mandated remediation requirements, the Partnership often enters into voluntary remediation programs with regulatory agencies. Depending on the results of on-going assessments and review of any data collected, the Partnership's liabilities for environmental remediation are updated based on new facts and circumstances. The actual costs incurred will depend on the actual amount and extent of contamination discovered, the final cleanup standards mandated by the Environmental Protection Agency (EPA) or other governmental authorities and other factors.

As of December 31, 2010, and 2009, the Partnership had an accrued liability of approximately $11.2 million and $14.1 million related to assessment and/or remediation costs associated with the historical use of polychlorinated biphenyls, petroleum hydrocarbons and mercury, enhancement of 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 ten years. As of December 31, 2010, and 2009, approximately $3.6 million and $3.0 million were recorded in *Other current liabilities* and approximately $7.6 million and $11.1 million were recorded in *Other Liabilities and Deferred Credits*.

Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)

In 2006, Texas Gas received notice from the EPA that Texas Gas is a potentially responsible party under the CERCLA of 1980 with respect to the LWD, Inc. Superfund Site in Calvert City, Kentucky. The Partnership does not expect the outcome of this matter to have a material effect on its financial condition, results of operations or cash flows.

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 EPA to promulgate new regulations pertaining to mobile sources, air toxins, areas of ozone non-attainment and acid rain. 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 will be identified which may require additional emission controls for compliance at as many as 12 facilities operated by the operating subsidiaries. In 2010, the EPA proposed to lower the 8-hour ozone standard set in 2008. Consequently, the EPA extended the deadline to designate non-attainment areas until March 2011 and the compliance deadline was extended to between 2014 and 2017. The Partnership is currently evaluating its potentially affected facilities to determine the costs necessary to comply with this standard.

In 2009, the EPA made a determination that greenhouse gases were a threat to the public health and the environment and may be regulated as "air pollutants" under the Clean Air Act. Beginning in 2011, the Partnership will be required to file reports with the EPA regarding greenhouse gas emissions from its facilities, mainly 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. As a result, the Partnership will conduct various facility surveys across its entire system to comply with the EPA's greenhouse gas emission calculations and reporting regulations. 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 Partnership does not expect the new federal rules and determinations regarding greenhouse gas emissions to 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, 2010, 2009 and 2008 were approximately $4.0 million, $4.8 million and $4.4 million. The following table summarizes minimum future commitments related to these items at December 31, 2010 (in millions):

2011	**$ 4.0**
2012	**3.6**
2013	**3.6**
2014	**3.0**
2015	**2.8**
Thereafter	**4.5**
Total	**$ 21.5**

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 existing at December 31, 2010. The commitments as of December 31, 2010, were approximately (in millions):

2011	**$ 30.8**
2012	**-**
2013	**-**
2014	**-**
2015	**-**
Thereafter	**-**
Total	**$ 30.8**

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 $11.1 million, $10.8 million and $6.4 million related to pipeline capacity agreements for the years ended December 31, 2010, 2009 and 2008. The future commitments related to pipeline capacity agreements as of December 31, 2010 were (in millions):

2011	$ **9.8**
2012	**9.0**
2013	**8.7**
2014	**8.3**
2015	**7.7**
Thereafter	**14.7**
Total	$ **58.2**

Note 4: Property, Plant and Equipment (PPE)

From 2006 through 2010, the Partnership was engaged in the construction of a significant amount of pipeline assets and related compression facilities. These projects resulted in significant capital expenditures over that period. By December 31, 2010, those projects were in service resulting in a significant reduction in capital expenditures in the 2010 period compared with 2009 and 2008. In 2010, the Partnership placed in service the remaining compression facilities associated with its Gulf Crossing Project, Fayetteville and Greenville Laterals and Haynesville Project. As a result, approximately $334.6 million was transferred from construction work in progress to plant. The assets associated with these projects will generally be depreciated over a term of 35 years.

The following table presents the Partnership's PPE as of December 31, 2010 and 2009 (in millions):

Category	**2010 Class Amount**	**Weighted-Average Useful Lives (Years)**	2009 Class Amount	Weighted-Average Useful Lives (Years)
Depreciable plant:				
Transmission	$ **6,282.2**	**37**	$ 6,040.8	37
Storage	**250.4**	**46**	275.1	45
Gathering	**88.5**	**19**	91.6	19
General	**121.2**	**18**	93.5	16
Rights of way and other	**110.0**	**30**	34.8	28
Total utility depreciable plant	**6,852.3**	**37**	6,535.8	37
Non-depreciable:				
Construction work in progress	**109.9**		231.4	
Storage	**48.4**		55.4	
Land	**16.9**		15.3	
Other	**16.3**		17.3	
Total other	**191.5**		319.4	
Total PPE	**7,043.8**		6,855.2	
Less: accumulated depreciation	**785.8**		577.3	
Total PPE, net	$ **6,258.0**		$ 6,277.9	

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, 2010 and 2009 (in millions):

	2010		2009	
	Gross PPE Investment	**Accumulated Depreciation**	Gross PPE Investment	Accumulated Depreciation
Bistineau storage	**$ 56.0**	**$ 10.1**	$ 58.0	$ 8.7
Mobile Bay Pipeline	**11.3**	**2.1**	11.3	1.7
Offshore and other assets	**19.2**	**12.4**	19.2	11.9
Total	**$ 86.5**	**$ 24.6**	$ 88.5	$ 22.3

Asset Dispositions and Impairments

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.

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.

In 2010, approximately 5.5 billion cubic feet (Bcf) of gas stored underground with a book value of $12.5 million was sold related to Phase III of the Western Kentucky Storage Expansion and a reduction in the amount of gas needed to support no-notice services. As a result, the Partnership recognized a gain of $17.5 million which was included in *Net (gain) loss on disposal of operating assets*.

In 2008, as a result of Phase III of the Western Kentucky Storage Expansion approximately 5.1 Bcf of gas stored underground with a book value of $11.8 million was sold, resulting in a gain of $34.4 million. In 2008, the Partnership also completed the sale of its investment in land and coal reserves along the Ohio River in northern Kentucky and southern Indiana for $16.5 million. These assets had no book value at the time of the sale. As a result, the Partnership recorded a gain of $16.5 million related to the sale. The gains were included in *Net (gain) loss on disposal of operating assets*.

In 2008, the Partnership completed a review of its non-contiguous offshore laterals and provided notice to the other interest holders of its intent to discontinue use of its portion of the available capacity for some of the assets. As a result, the Partnership reviewed the assets for recoverability and recorded an impairment charge of approximately $3.0 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):

	2010	2009
Balance at beginning of year	**$ 18.0**	$ 18.0
Liabilities recorded	**-**	2.1
Liabilities settled	**(0.3)**	(2.9)
Accretion expense	**1.0**	0.8
Balance at end of year	**18.7**	18.0
Less: Current portion of asset retirement obligations	**(1.5)**	-
Long-term asset retirement obligations	**$ 17.2**	$ 18.0

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 $51.7 million and $47.0 million as of December 31, 2010 and 2009, 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, 2010 and 2009, 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 nineteen 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, 2010 and 2009 (in millions):

	2010	2009
Regulatory Assets:		
Pension	**$ 10.6**	$ 10.6
Tax effect of AFUDC equity	**5.1**	5.5
Unamortized debt expense and premium on reacquired debt	**7.9**	8.9
Postretirement benefits other than pension	**4.2**	5.4
Fuel tracker	**7.1**	0.6
Total regulatory assets	**$ 34.9**	$ 31.0
Regulatory Liabilities:		
Cashout and fuel tracker	**$ 0.3**	$ 1.9
Provision for other asset retirement	**51.7**	47.0
Unamortized discount on long-term debt	**(2.3)**	(2.9)
Postretirement benefits other than pension	**23.7**	17.6
Other	**0.4**	0.5
Total regulatory liabilities	**$ 73.8**	$ 64.1

Note 7: Financing

Long-Term Debt

The following table presents all long-term debt issues outstanding as of December 31, 2010 and 2009 (in millions):

	2010	2009
Notes and Debentures:		
Boardwalk Pipelines		
5.88% Notes due 2016	**$ 250.0**	$ 250.0
5.20% Notes due 2018	**185.0**	185.0
5.50% Notes due 2017	**300.0**	300.0
5.75% Notes due 2019	**350.0**	350.0
Gulf South		
6.30% Notes due 2017	**275.0**	275.0
5.75% Notes due 2012	**225.0**	225.0
5.05% Notes due 2015	**275.0**	275.0
Texas Gas		
7.25% Debentures due 2027	**100.0**	100.0
4.60% Notes due 2015	**250.0**	250.0
5.50% Notes due 2013	**250.0**	250.0
Total notes and debentures	**2,460.0**	2,460.0
Revolving Credit Facility:		
Boardwalk Pipelines	**285.0**	135.0
Gulf South	**228.5**	228.5
Texas Gas	**190.0**	190.0
Total revolving credit facility	**703.5**	553.5
Subordinated Loan Agreement with BPHC	**100.0**	100.0
	3,263.5	3,113.5
Less: unamortized debt discount	**(11.2)**	(13.5)
Total Long-Term Debt	**$ 3,252.3**	$ 3,100.0

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

2011	$ -
2012	1,028.5
2013	250.0
2014	-
2015	525.0
Thereafter	1,460.0
Total long-term debt	$ 3,263.5

Notes and Debentures

There were no new debt issuances for the year ended December 31, 2010. However, for the years ended December 31, 2009 and 2008, the Partnership completed the following debt issuances, the proceeds of which were used to directly and indirectly fund the Partnership's capital projects. BPHC waived the mandatory prepayment required pursuant to provisions associated with the Subordinated Loans described below as a result of the August 2009 debt issuance (in millions, except interest rate percentage):

Date of Issuance	Issuing Subsidiary	Amount of Issuance	Purchaser Discounts and Expenses	Net Proceeds	Interest Rate	Maturity Date	Interest Payable
August 2009	Boardwalk Pipelines	$350.0	$3.3	$346.7	5.75%	September 15, 2019	March 15 and September 15
March 2008	Texas Gas	250.0	2.8	247.2	5.50%	April 1, 2013	April 1 and October 1

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, 2010 and 2009, the weighted-average interest rate of the Partnership's notes and debentures was 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, 2010, Boardwalk Pipelines and its operating subsidiaries were in compliance with their debt covenants.

Subsequent Events. In January 2011, the Partnership received net proceeds of approximately $322.2 million after deducting initial purchaser discounts and offering expenses of $2.8 million from the sale of $325.0 million of 4.50% senior unsecured notes of Texas Gas due February 1, 2021 (2021 Notes). The net proceeds of the offering were used to reduce borrowings under the Partnership's revolving credit facility. BPHC waived the mandatory prepayment pursuant to provisions associated with the Subordinated Loan discussed below. In January 2011, the Partnership notified the holders of Texas Gas' 5.5% notes due April 1, 2013, that it will redeem $135.0 million of those notes in February 2011 at the redemption price provided for in the indenture governing such notes. The Partnership will borrow funds under its revolving credit facility to fund this redemption.

Revolving Credit Facility

The Partnership has a revolving credit facility which has aggregate lending commitments of $950.0 million. Borrowings outstanding under the credit facility as of December 31, 2010 and 2009, were $703.5 million and $553.5 million with a weighted-average borrowing rate of 0.53% and 0.48%. The proceeds from the 2021 Notes issuance were used to reduce borrowings under the revolving credit facility and as of February 18, 2011, the Partnership had $383.5 million in loans outstanding under the revolving credit facility with a weighted-average interest rate of 0.52% and had no letters of credit issued. At such date the Partnership had available borrowing capacity of $566.5 million. As discussed in *Subsequent Events*, in February 2011, the Partnership will borrow funds under the revolver credit facility to pay the redemption price for $135.0 million of Texas Gas's 2013 Notes.

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, 2010. 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, commencing December 2009, 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, 2010 and 2009, the Partnership had $100.0 million outstanding under the Subordinated Loan Agreement with no additional borrowing capacity available.

Common Unit Offering

For the year ended December 31, 2010, no issuances or sales of common units occurred. For the years ended December 31, 2009 and 2008, the Partnership completed the following issuances and sales of common units, the proceeds of which were directly and indirectly used 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. The following table shows selected information related to these equity issuances (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
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 (3)	47.4
October 2008 (2)	21.2	23.13	-	500.0	121.8	47.4
June 2008	10.0	25.30	9.4	248.8	100.7	47.4

(1) BPHC waived the mandatory prepayment required pursuant to provisions associated with the Subordinated Loans as a result of this offering.
(2) Sold to BPHC in a private placement.
(3) Includes the conversion on a one-for-one basis of all of the 33.1 million subordinated units into common units in November 2008.

Class B Units

In June 2008, the Partnership issued and sold to BPHC approximately 22.9 million class B units representing limited partner interests (class B units) for $30.00 per class B unit, or an aggregate purchase price of $686.0 million. The Partnership's general partner also contributed $14.0 million to the Partnership to maintain its 2% interest. The Partnership used the proceeds of $700.0 million to directly and indirectly fund a portion of the costs of its expansion projects. The class B units will be convertible into common units upon demand by the holder on a one-for-one basis at any time after June 30, 2013. The class B units began sharing in income allocations and distributions with respect to the third quarter 2008.

Conversion of Subordinated Units

In November 2008, the Partnership satisfied the last of the earnings and distribution tests contained in its partnership agreement for the conversion into common units on a one-for-one basis of all of the 33.1 million then outstanding subordinated units held by BPHC. Subsequently, all of the subordinated units converted to common units.

Summary of Changes in Outstanding Units

The following table summarizes changes in the Partnership's common, class B and subordinated units since January 1, 2008 (in millions):

	Common Units	Class B Units	Subordinated Units
Balance, January 1, 2008	90.6	-	33.1
Common units issued in connection with underwritten offerings	10.0	-	-
Class B units issued and sold to BPHC in a private placement	-	22.9	-
Common units issued and sold to BPHC in a private placement	21.2	-	-
Conversion of subordinated units to common units	33.1	-	(33.1)
Balance, December 31, 2008	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	-

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, 2010 and 2009, the Partnership had an accrued liability of approximately $16.0 million and $26.7 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

Subsidiaries of the Partnership use 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 $3.6 million and $2.3 million of gas stored underground at December 31, 2010 and 2009, 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 billion cubic feet (Bcf) of gas with a book value of $8.8 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. At December 31, 2010, approximately 7.7 Bcf of anticipated future sales of natural gas and cash for fuel reimbursement were hedged with derivatives having settlement dates in 2011. The derivatives qualify for cash flow hedge accounting and are designated as such. The Partnership has also periodically used derivatives as cash flow hedges of interest rate risk in anticipation of debt offerings.

All of the Partnership's currently outstanding 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 fair values of derivatives existing as of December 31, 2010 and 2009, were included in the following captions in the Consolidated Balance Sheets (in millions):

	Asset Derivatives				**Liability Derivatives**			
	December 31, 2010		December 31, 2009		**December 31, 2010**		December 31, 2009	
	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	$ 6.2	Other current liabilities	**$ 1.7**	Other current liabilities	$ -

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, 2010 and 2009.

The effective component of unrealized gains and losses resulting from changes in fair values of the derivatives designated as cash flow hedges are deferred as a component of accumulated other comprehensive income or loss (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, 2010 and 2009.

The Partnership estimates that approximately $3.3 million of net losses reported in AOCI as of December 31, 2010, are expected to be reclassified into earnings within the next twelve months. 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	-
	$ 6.0		$ 12.9		$ 0.1

(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	Net gain/(loss) on disposal of operating assets and related contracts	$ (0.4)
Interest rate contracts (1)	-	Interest expense	(1.7)	N/A	-
	$ 10.5		$ 16.9		$ (0.4)

(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. At December 31, 2010, all of the Partnership's derivatives were with two counterparties, however outstanding asset positions under derivative contracts have not resulted in a material concentration of credit risk.

In accordance with the contracts governing the Partnership's derivatives, the counterparty or the Partnership may be required to post cash collateral when credit risk exceeds certain thresholds. Contractual provisions with one counterparty require that cash collateral be posted to the extent the fair value amount payable to the other party exceeds $5.0 million. The threshold for posting collateral with the other counterparty varies based on the credit ratings of the contracting subsidiary of the Partnership or the counterparty. Based on credit ratings at December 31, 2010, the Partnership would be required to post cash collateral to the extent the fair value amount payable to the other party exceeds $10.0 million and the counterparty would be required to post cash collateral to the extent the fair value amount payable to the Partnership exceeds $25.0 million. Additionally, the outstanding derivative contracts contain ratings triggers which would require the Partnership's contracting subsidiary to immediately post collateral in the form of cash or a letter of credit for the full value of any of the derivatives that are in a liability position if the subsidiary's credit rating were reduced below investment grade. At December 31, 2010 and 2009, the Partnership was not required to post any collateral nor did it hold any collateral associated with its outstanding derivatives.

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 its Pension Plan, including a minimum of $3.0 million which is the amount included in rates. In 2010 and 2009, the Partnership funded $9.2 million and $6.0 million to the Pension Plan and expects to fund approximately $8.8 million to the plan in 2011. The Partnership does not anticipate that any Pension Plan assets will be returned to the Partnership during 2011. In 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 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 2010, the Partnership made contributions of $0.2 million to the PBOP plan and did not make any contributions to the PBOP plan in 2009. Due to plan changes regarding benefits available to current and future retirees described below, the PBOP plan is currently in an overfunded status, therefore the Partnership does not expect to make any contributions to the plan in

2011. The Partnership does not anticipate that any plan assets will be returned to the Partnership during 2011. 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, 2010 and 2009, were as follows (in millions):

	Retirement Plans		PBOP	
	For the Year Ended December 31,		For the Year Ended December 31,	
	2010	2009	**2010**	2009
Change in benefit obligation:				
Benefit obligation at beginning of period	**$ 122.0**	$ 109.9	**$ 53.2**	$ 52.4
Service cost	**3.8**	3.7	**0.5**	0.5
Interest cost	**6.9**	7.0	**2.8**	3.0
Plan participants' contributions	**-**	-	**1.0**	1.0
Actuarial loss (gain)	**4.8**	6.5	**(1.2)**	(0.1)
Benefits paid	**(5.0)**	(5.1)	**(4.6)**	(3.6)
Benefit obligation at end of period	**$ 132.5**	$ 122.0	**$ 51.7**	$ 53.2
Change in plan assets:				
Fair value of plan assets at beginning of period	**$ 90.4**	$ 74.2	**$ 72.8**	$ 66.7
Actual return on plan assets	**10.8**	15.3	**3.9**	8.7
Benefits paid	**(5.0)**	(5.1)	**(4.6)**	(3.6)
Company contributions	**9.3**	6.0	**0.2**	-
Plan participants' contributions	**-**	-	**1.0**	1.0
Fair value of plan assets at end of period	**$ 105.5**	$ 90.4	**$ 73.3**	$ 72.8
Funded status	**$ (27.0)**	$ (31.6)	**$ 21.6**	$ 19.6
Items not recognized as components of net periodic cost:				
Prior service cost (credit)	**$ 0.1**	$ 0.1	**$ (39.7)**	$ (47.5)
Net actuarial loss	**25.2**	25.7	**16.6**	18.7
Total	**$ 25.3**	$ 25.8	**$ (23.1)**	$ (28.8)

At December 31, 2010 and 2009, the following aggregate information relates only to the underfunded plans (in millions):

	For the Year Ended December 31,	
	2010	2009
Projected benefit obligation	**$ 132.5**	$ 122.0
Accumulated benefit obligation	**119.3**	109.3
Fair value of plan assets	**105.5**	90.4

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, 2010, 2009 and 2008 were as follows (in millions):

	Retirement Plans			PBOP		
	For the Year Ended December 31,			For the Year Ended December 31,		
	2010	2009	2008	**2010**	2009	2008
Service cost	**$ 3.8**	$ 3.7	$ 3.7	**$ 0.5**	$ 0.5	$ 0.6
Interest cost	**6.9**	7.0	6.5	**2.8**	3.0	3.2
Expected return on plan assets	**(7.0)**	(5.6)	(6.8)	**(3.8)**	(3.4)	(5.0)
Amortization of prior service credit	**-**	-	-	**(7.8)**	(7.7)	(7.8)
Amortization of unrecognized net loss	**1.5**	2.1	0.1	**0.9**	1.5	0.1
Settlement charge	**-**	-	0.3	**-**	-	-
Regulatory asset (increase) decrease	**-**	(1.1)	-	**5.4**	5.4	5.4
Net periodic benefit cost	**$ 5.2**	$ 6.1	$ 3.8	**$ (2.0)**	$ (0.7)	$ (3.5)

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 5 to 6 years, resulting in an annual decrease in the regulatory asset. 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
2011	$ 6.7	$ 4.1
2012	7.3	3.9
2013	10.4	3.7
2014	11.6	3.7
2015	12.0	3.7
2016-2020	81.4	18.1

Weighted –Average Assumptions

Weighted-average assumptions used to determine benefit obligations for the years ended December 31, 2010 and 2009, were as follows:

	Retirement Plans		PBOP	
	For the Year Ended December 31,		For the Year Ended December 31,	
	2010	2009	**2010**	2009
Discount rate	**5.00%**	5.70%	**5.375%**	5.70%
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 For the Year Ended December 31,			PBOP For the Year Ended December 31,		
	2010	2009	2008	**2010**	2009	2008
Discount rate	**5.70%**	6.30%	6.00%	**5.70%**	6.30%	6.00%
Expected return on plan assets	**7.50%**	7.50%	7.50%	**5.35%**	5.35%	6.15%
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, 2010 (in millions):

Effect of 1% Increase:		**2010**
Benefit obligation at end of year	**$**	**1.5**
Total of service and interest costs for year		**0.1**
Effect of 1% Decrease:		
Benefit obligation at end of year	**$**	**(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 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. For December 31, 2009, health care costs for the plans were assumed to increase 9% for 2010-2011 grading down to 5% in 0.5% annual increments for participants not eligible for Medicare and 9% 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, 2010 and 2009, was $105.5 million (or 50.2%) and $90.4 million (or 48.6%), 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. Level 2 short-term investments include commercial paper for which all inputs are observable. 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, 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 and other invested assets	-	45.9	39.4	85.3
Total investments	$ 122.8	$ 47.9	$ 39.4	$ 210.1

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, 2009 (in millions):

	Master Trust Assets			
	Level 1	**Level 2**	**Level 3**	**Total**
Equity securities	$ 26.2	$ -	$ -	$ 26.2
Short-term investments	11.5	-	-	11.5
Corporate and other taxable bonds	-	71.8	-	71.8
Asset-backed securities	-	4.0	-	4.0
Limited partnerships and other invested assets	-	36.8	35.6	72.4
Total investments	$ 37.7	$ 112.6	$ 35.6	$ 185.9

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
Balance, January 1, 2009	$ 54.6
Actual return on assets still held	14.5
Actual return on assets sold	0.6
Purchases, sales and settlements	2.7
Net transfers in/(out) of Level 3	(36.8)
Balance, December 31, 2009	$ 35.6
Actual return on assets still held	4.8
Actual return on assets sold	1.2
Purchases, sales and settlements	(2.2)
Net transfers in/(out) of Level 3	-
Balance, December 31, 2010	$ 39.4

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. U.S treasury securities which are considered highly liquid government bonds for which quoted market prices are available 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 2009 limited partnership investments consist primarily of hedge funds, whose fair value represents the PBOP trust's share of the net asset value of each partnership, as determined by the general partner. The limited partnership investments contain withdrawal provisions greater than 90 days and are considered Level 3 investments. The limited partnership investments were redeemed in 2010.

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 taxable bonds	-	18.1	-	18.1
Tax exempt securities	-	32.5	-	32.5
Limited partnerships	-	-	0.1	0.1
Total investments	$ 14.3	$ 58.9	$ 0.1	$ 73.3

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, 2009 (in millions):

	PBOP Trust Assets			
	Level 1	Level 2	Level 3	Total
Short-term investments	$ 9.5	$ -	$ -	$ 9.5
Asset-backed securities	-	2.0	-	2.0
Corporate and other taxable bonds	-	17.2	-	17.2
Tax exempt securities	-	28.5	-	28.5
Limited partnerships	-	-	15.6	15.6
Total investments	$ 9.5	$ 47.7	$ 15.6	$ 72.8

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, 2009	$ 22.9
Actual return on assets still held	3.7
Actual return on assets sold	-
Purchases, sales and settlements	(11.0)
Net transfers in/(out) of Level 3	-
Balance, December 31, 2009	$ 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	$ 0.1

Investment strategy

Pension: The Partnership employs a total-return approach whereby a mix of equities and fixed income investments is used to maximize the long-term return on plan assets for a prudent level of risk and manage cash flows according to 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 the plan liabilities, plan funded status and corporate financial conditions. 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 maturity equity and short term securities. Alternative investments, including limited partnerships, have been used to enhance risk adjusted long term returns while improving portfolio diversification. 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, 2010, approximately 92% 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 $6.9 million, $6.6 million and $5.7 million for the years ended December 31, 2010, 2009 and 2008.

Boardwalk Pipeline Partners Unit Appreciation Rights and Cash Bonus Plan

In 2010, the Partnership established the Boardwalk Pipeline Partners Unit Appreciation Rights and Cash Bonus Plan (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. Awards made under this plan are intended to encourage superior performance, attract and retain employees who are essential for the Partnership's growth and profitability and to encourage those employees to devote their best efforts to advancing the Partnership's business over both long and short-term time horizons. The Partnership does not expect to make additional grants to employees under the Strategic Long-Term Incentive Plan (SLTIP), under which substantially all of the available awards have been granted, or the Long-Term Incentive Plan (LTIP). The Partnership expects to continue to use the LTIP to provide annual awards of common units to certain members of its Board.

UARs. The economic value of the UARs is directly tied to the value of the Partnership's common units, but these awards are payable in cash and 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 to the extent the fair market value (as defined in the plan) of a common unit on such date exceeds the exercise price; limited to the applicable dollar cap amount per UAR (UAR Cap). 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, 2010, and changes during 2010 is presented below:

	UARs	**Weighted Average Exercise Price ($)**	**Weighted-Average Vesting Period (in years)**
Outstanding at January 1, 2010	-	-	-
Granted (1)	368,956	$ 30.36	3.0
Outstanding at December 31, 2010 (2)	**368,956**	**30.36**	**3.0**

(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 and remaining weighted-average vesting period of outstanding awards at the end of the period.

The UARs granted on December 16, 2010, will vest and be paid upon the expiration of a three-year restricted period, subject to a UAR Cap of $15.76. The fair value of approximately $4.14 for each UAR granted during 2010, or $1.5 million in total, was determined to be the difference between 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 fair value of UARs outstanding at December 31, 2010, was approximately $4.32 per UAR, or $1.6 million. The value of each call was estimated using the standard Black-Scholes valuation model using the assumptions described below.

	December 16, 2010	**December 31, 2010**
Expected life (years)	3.0	3.0
Risk free interest rate (1)	1.1%	1.0%
Expected volatility(2)	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 less than $0.1 million for the year ended December 31, 2010, related to the UARs. As of December 31, 2010, there was $1.4 million of total unrecognized compensation cost related to the non-vested portion of the UARs.

Long-Term Cash Bonuses. In 2010, The Partnership granted to certain employees $1.7 million of Long-Term Cash Bonuses under the UAR and Cash Bonus Plan. Each Long-Term Cash Bonus 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. 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 less than $0.1 million for the year ended December 31, 2010, related to the Long-Term Cash Bonuses. As of December 31, 2010, there was $1.5 million of total unrecognized compensation cost related to the non-vested portion of the Long-Term Cash Bonuses.

Strategic Long-Term Incentive Plan

The Partnership's Strategic Long-Term Incentive Plan (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, 2010 and 2009, and changes during the years ended December 31, 2010 and 2009, is presented below:

	Phantom GP Units	Total Fair Value (in millions)	Weighted-Average Vesting Period (in years)
Outstanding at January 1, 2009 (1)	377	$ 16.9	2.7
Granted (2)	79	3.9	2.9
Paid	-	-	-
Forfeited	-	-	-
Outstanding at December 31, 2009 (1)	456	20.6	2.0
Paid	**(88)**	**(2.9)**	**-**
Forfeited	**(1)**	**-**	**-**
Outstanding at December 31, 2010 (1)	**367**	**17.6**	**1.5**

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

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 $4.9 million, $3.8 million and $1.1 million in *Administrative and general* expenses during 2010, 2009 and 2008 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, 2010, was $6.9 million. No additional grants of Phantom GP Units are expected to be made under the SLTIP.

Long-Term Incentive Plan

The Partnership reserved 3,525,000 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 Long-Term Incentive Plan (LTIP). The Partnership has granted phantom common units (Phantom Common Units) under the plan. Each such grant: includes a tandem grant of Distribution Equivalent Rights (DERs); vests 50% on the second anniversary of the grant date and 50% on the third anniversary of the grant date; and will be payable to the grantee in cash 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 plus the vested amount then credited to the grantee's DER account, less applicable taxes. 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, 2010 and 2009, and changes during the years ended December 31, 2010 and 2009, is presented below:

	Phantom Common Units	Total Fair Value (in millions)	Weighted-Average Vesting Period (in years)
Outstanding at January 1, 2009 (1)	108,288	2.1	1.8
Granted (2)	1,245	-	1.5
Paid	(2,462)	(0.1)	-
Forfeited	-	-	-
Outstanding at December 31, 2009 (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**

(1) Represents fair value and remaining weighted-average vesting period of outstanding awards at the end of the period.
(2) The grant date fair value of these awards was less than $0.1 million.

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 December 31, 2010 and 2009, of $31.13 and $30.03 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 $1.1 million, $1.7 million and $0.4 million in *Administrative and general* expenses during 2010, 2009 and 2008 for the ratable recognition of the Phantom Common Unit awards fair value. The total estimated remaining unrecognized compensation expense related to the Phantom Common Units outstanding at December 31, 2010, was $0.4 million. No new grants of Phantom Common Units are expected to be made under the LTIP.

In 2010 and 2009, the general partner purchased 1,500 of the Partnership's common units each year in the open market at a price of $29.05 and $20.58 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, 2010, 3,517,708 units were available for grants under the LTIP.

Other

In 2009, the Partnership incurred and paid approximately $2.0 million related to a small reduction in force that affected approximately 50 employees. In fourth quarter 2008, the Partnership consolidated and changed its employee paid time off benefits policy resulting in the Partnership reversing $7.2 million of its liability associated with paid time off that would otherwise have been available to employees as of January 1, 2009. The reversal resulted in a reduction to *Operation and maintenance* expenses of $4.9 million and *Administrative and general* expenses of $2.3 million.

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	
	Target Amount	Limited Partner Unitholders (1)	General Partner and IDRs
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, subordinated 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 and Subordinated Unitholders (1)	Amount Paid to Class B Unitholder (2)	Amount Paid to General Partner (Including IDRs) (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
November 10, 2008	0.475	63.6	6.9	3.7
August 11, 2008	0.470	62.8	-	3.4
May 12, 2008	0.465	57.6	-	2.9
February 25, 2008	0.460	56.9	-	2.7

(1) All of the 33.1 million subordinated units converted to common units on a one-for-one basis two days following the November 10, 2008 distribution.
(2) The class B units began sharing in income allocations and distributions with respect to the third quarter 2008.
(3) In 2010, 2009 and 2008, the Partnership paid $18.2 million, $13.3 million and $7.5 million in distributions on behalf of IDRs.

In February 2011, the Partnership declared a quarterly cash distribution to unitholders of record of $0.52 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, 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	$ 289.4	$ 250.2	$ 14.2	$ 25.0
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	$ 162.7	$ 142.9	$ 1.9	$ 17.9
Weighted-average units outstanding		161.6	22.9	
Net income (loss) per unit		$ 0.88	$ 0.08	

The following table provides a reconciliation of net income and the assumed allocation of net income to the common, class B and subordinated units for purposes of computing net income per unit for the year ended December 31, 2008 (in millions, except per unit data):

	Total	Common Units	Class B Units (1)	Subordinated Units (2)	General Partner And IDRs
Net income	$ 294.0				
Declared distribution	286.7	$ 211.7	$ 13.7	$ 46.7	$ 14.6
Assumed allocation of undistributed net income	7.3	5.6	-	1.5	0.2
Assumed allocation of net income	$ 294.0	$ 217.3	$ 13.7	$ 48.2	$ 14.8
Weighted-average units outstanding		104.2	22.9	28.7	
Net income per unit		$ 2.09	$ 0.60	$ 1.68	

(1) The number of units shown is weighted from July 1, 2008, which is the date the class B units became eligible to participate in income allocations. As a result, no assumed allocations of net income were made to the class B units for purposes of computing net income per unit prior to July 1, 2008.
(2) All of the 33.1 million subordinated units converted to common units on a one-to-one basis in November 2008.

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, 2010, 2009 and 2008 (in millions):

	For the Year Ended December 31,		
	2010	2009	2008
Current expense:			
State	**$ 0.3**	**$** 0.2	$ 0.7
Total	**0.3**	0.2	0.7
Deferred provision:			
State	**0.2**	0.1	0.3
Total	**0.2**	0.1	0.3
Income taxes	**$ 0.5**	**$** 0.3	$ 1.0

The Partnership's tax years 2007 through 2010 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, 2010, 2009 and 2008. As of December 31, 2010 and 2009, 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, 2010 and 2009. The fair market value of the debt that is not publicly traded is based on market prices of similar debt at December 31, 2010 and 2009.

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, 2010 and 2009, were as follows (in millions):

	December 31, 2010		December 31, 2009	
Financial Assets	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Cash and cash equivalents	**$ 55.0**	**$ 55.0**	$ 45.8	$ 45.8
Financial Liabilities				
Long-term debt	**$ 3,152.3**	**$ 3,314.3**	$ 3,000.0	$ 3,060.6
Long-term debt – affiliate	**100.0**	**106.3**	100.0	108.0

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, 2010	As of December 31, 2009
Loss on cash flow hedges	**$ (13.7)**	$ (6.7)
Deferred components of net periodic benefit cost	**(25.8)**	(18.7)
Total Accumulated other comprehensive loss	**$ (39.5)**	$ (25.4)

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,					
	2010		2009		2008	
Customer	**Revenue**	**%**	Revenue	%	Revenue	%
Devon Gas Services, LP	**$ 143.5**	**13%**	$ 102.6	11%	$ 47.2	6%

Gas Loaned to Customers

Natural gas price volatility can cause changes in credit risk related to gas loaned to customers. 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 that gas was approximately $54.7 million. As of December 31, 2009, the amount of gas owed to the operating subsidiaries due to gas imbalances and gas loaned under PAL agreements was approximately 14.9 TBtu. Assuming an average market price during December 2009 of $5.36 per MMBtu, the market value of this gas at December 31, 2009, would have been approximately $79.9 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 to the Partnership a variety of corporate services under services agreements, including but not limited to, information technology, tax, risk management, internal audit and corporate development services, plus allocated overheads. Loews charged $16.8 million, $17.1 million and $14.5 million for the years ended December 31, 2010, 2009 and 2008 to the Partnership for performing these services.

Distributions paid related to limited partner units held by BPHC and the 2% general partner interest and IDRs held by Boardwalk GP were $267.9 million, $264.2 million and $181.1 million for the years ended December 31, 2010, 2009 and 2008.

In 2009, Boardwalk Pipelines entered into a $200.0 million Subordinated Loan Agreement with BPHC and the Partnership issued and sold 6.7 million common units to BPHC as well as entered into a registration rights agreement. 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. Note 7 contains more information regarding these transactions.

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

	For the Year Ended December 31,		
	2010	2009	2008
Cash paid during the period for:			
Interest (net of amount capitalized)	**$ 146.3**	$ 124.4	$ 42.8
Income taxes, net	**$ 0.4**	$ 0.2	$ 0.8
Non-cash adjustments:			
Accounts payable and PPE	**$ 29.5**	$ 173.2	$ 86.8
Accrued registration rights costs	**$ -**	$ 6.1	$ 20.6

Note 17: Selected Quarterly Financial Data (Unaudited)

The following tables summarize selected quarterly financial data for 2010 and 2009 for the Partnership (in millions, except for earnings per unit):

	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	**$ 88.9**	**$ 55.8**	**$ 54.4**	**$ 90.3**
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**

	2009 For the Quarter Ended:			
	December 31	September 30	June 30	March 31
Operating revenues	$ 279.0	$ 205.4	$ 201.4	$ 223.4
Operating expenses	170.7	151.0	148.2	144.8
Operating income	108.3	54.4	53.2	78.6
Interest expense, net	36.8	35.7	32.9	26.5
Other (income) expense	(0.2)	-	-	(0.2)
Income before income taxes	71.7	18.7	20.3	52.3
Income taxes	0.1	(0.1)	-	0.3
Net income	$ 71.6	$ 18.8	$ 20.3	$ 52.0
Net income per unit:				
Common units	$ 0.37	$ 0.10	$ 0.12	$ 0.29
Class B units	$ 0.17	$ (0.10)	$ (0.09)	$ 0.11
Total Comprehensive Income	$ 73.6	$ 11.7	$ 12.3	$ 55.2

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, 2010 and 2009. 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, 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 Balance Sheets as of December 31, 2009
(in millions)

Assets	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Cash and cash equivalents	$ -	$ 45.6	$ 0.2	$ -	$ 45.8
Receivables	-	-	137.9	(28.9)	109.0
Gas stored underground	-	-	2.1	-	2.1
Prepayments	-	-	10.1	-	10.1
Advances to affiliates	-	128.0	-	(128.0)	-
Other current assets	0.3	-	25.2	(1.6)	23.9
Total current assets	0.3	173.6	175.5	(158.5)	190.9
Investment in consolidated subsidiaries	754.9	4,592.2	-	(5,347.1)	-
Property, plant and equipment, gross	0.6	-	6,854.6	-	6,855.2
Less–accumulated depreciation and amortization	(0.4)	-	(576.9)	-	(577.3)
Property, plant and equipment, net	0.2	-	6,277.7	-	6,277.9
Other noncurrent assets	0.4	2.1	424.5	-	427.0
Advances to affiliates – noncurrent	2,638.2	121.6	165.8	(2,925.6)	-
Total other assets	2,638.6	123.7	590.3	(2,925.6)	427.0
Total Assets	$ 3,394.0	$ 4,889.5	$ 7,043.5	$ (8,431.2)	$ 6,895.8

Liabilities & Partners' Capital/Member's Equity	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Payables	$ 8.9	$ 0.3	$ 104.5	$ (28.9)	$ 84.8
Advances from affiliates	-	-	128.0	(128.0)	-
Other current liabilities	0.3	16.9	150.5	(1.6)	166.1
Total current liabilities	9.2	17.2	383.0	(158.5)	250.9
Total long-term debt	-	1,313.5	1,786.5	-	3,100.0
Payable to affiliate	20.6	2,804.0	121.6	(2,925.6)	20.6
Other noncurrent liabilities	-	(0.1)	160.2	-	160.1
Total other liabilities and deferred credits	20.6	2,803.9	281.8	(2,925.6)	180.7
Total partners' capital/member's equity	3,364.2	754.9	4,592.2	(5,347.1)	3,364.2
Total Liabilities and Partners' Capital/Member's Equity	$ 3,394.0	$ 4,889.5	$ 7,043.5	$ (8,431.2)	$ 6,895.8

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, affiliate, 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	-	-	966.3	(57.1)	909.2
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	-	-	671.8	(57.1)	614.7
Operating income	-	-	294.5	-	294.5
Other deductions (income):					
Interest expense	-	49.9	75.4	-	125.3
Interest expense, affiliate, 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)	(162.7)	(120.5)	79.9	334.8	131.5
					-
Income before income taxes	162.7	120.5	214.6	(334.8)	163.0
Income Taxes (Benefit)	-	-	0.3	-	0.3
Net Income	$ 162.7	$ 120.5	$ 214.3	$ (334.8)	$ 162.7

Condensed Consolidating Statements of Income for the Year Ended December 31, 2008
(in millions)

	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Operating revenues:					
Gas transportation	$ -	$ -	$ 712.7	$ (14.5)	$ 698.2
Parking and lending	-	-	16.3	-	16.3
Gas storage	-	-	51.6	(0.1)	51.5
Other	-	-	18.8	-	18.8
Total operating revenues	-	-	799.4	(14.6)	784.8
Operating cost and expenses:					
Fuel and gas transportation	-	-	116.9	(14.5)	102.4
Operation and maintenance	-	-	119.9	-	119.9
Administrative and general	(0.2)	-	106.2	-	106.0
Other operating costs and expenses	0.2	-	109.7	-	109.9
Total operating costs and Expenses	-	-	452.7	(14.5)	438.2
Operating income (loss)	-	-	346.7	(0.1)	346.6
Other deductions (income):					
Interest expense	0.1	82.5	58.1	(83.0)	57.7
Interest income	(54.9)	(10.4)	(20.5)	82.9	(2.9)
Equity in earnings of subsidiaries	(239.2)	(311.3)	-	550.5	-
Miscellaneous other income, net	-	-	(3.2)	-	(3.2)
Total other deductions (income)	(294.0)	(239.2)	34.4	550.4	51.6
Income before income taxes	294.0	239.2	312.3	(550.5)	295.0
Income Taxes	-	-	1.0	-	1.0
Net Income	$ 294.0	$ 239.2	$ 311.3	$ (550.5)	$ 294.0

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	$ 165.0	$ (85.0)	$ 443.0	$ (122.5)	$ 400.5
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	(136.2)	(8.0)	(535.5)	7.9	(671.8)
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	(28.8)	1.0	92.6	114.6	179.4
(Decrease) Increase in Cash and Cash Equivalents	-	(92.0)	0.1	-	(91.9)
Cash and Cash Equivalents at Beginning of Period	-	137.6	0.1	-	137.7
Cash and Cash Equivalents at End of Period	$ -	$ 45.6	$ 0.2	$ -	$ 45.8

Condensed Consolidating Statements of Cash Flow for the Year Ended December 31, 2008
(in millions)

	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Net Cash Provided by (Used In) Operating Activities	$ 294.4	$ (80.8)	$ 375.9	$ (239.2)	$ 350.3
Investing Activities:					
Capital expenditures	-	-	(2,652.5)	-	(2,652.5)
Proceeds from sale of operating assets, net	-	-	63.8	-	63.8
Proceeds from insurance reimbursements and other recoveries	-	-	4.7	-	4.7
Advances to affiliates, net	-	1,505.6	32.2	(1,536.2)	1.6
Distribution from consolidated subsidiary	21.3	-	-	(21.3)	-
Investment in consolidated subsidiary	-	(1,268.1)	-	1,268.1	-
Note receivable – affiliate	-	(153.2)	-	153.2	-
Purchases of short-term investments	-	(175.0)	-	-	(175.0)
Net Cash Provided by (Used in) Investing Activities	21.3	(90.7)	(2,551.8)	(136.2)	(2,757.4)
Financing Activities:					
Proceeds from long-term debt, net of issuance costs	-	-	247.2	-	247.2
Proceeds from borrowings on revolving credit agreement	-	285.0	1,199.0	-	1,484.0
Repayment of borrowings on revolving credit agreement	-	-	(692.0)	-	(692.0)
Notes payable to affiliates	-	-	153.2	(153.2)	-
Contribution from parent	-	-	1,268.1	(1,268.1)	-
Distributions paid	(260.5)	(260.5)	-	260.5	(260.5)
Advances from affiliates, net	(1,504.0)	(32.2)	-	1,536.2	-
Proceeds from sale of common units, net of related transaction costs	733.6	-	-	-	733.6
Proceeds from sale of class B units	686.0	-	-	-	686.0
Capital contribution from general partner	29.2	-	-	-	29.2
Net Cash (Used in) Provided by Financing Activities	(315.7)	(7.7)	2,175.5	375.4	2.227.5
Decrease in Cash and Cash Equivalents	-	(179.2)	(0.4)	-	(179.6)
Cash and Cash Equivalents at Beginning of Period	-	316.8	0.5	-	317.3
Cash and Cash Equivalents at End of Period	$ -	$ 137.6	$ 0.1	$ -	$ 137.7

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Our principal executive officer (CEO) and principal financial officer (CFO) undertook an evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report. The CEO and CFO have concluded that our disclosure controls and procedures were effective as of December 31, 2010.

Changes in Internal Control over Financial Reporting

During the third quarter 2010, we implemented a new enterprise resource planning system, including a replacement of the previous general ledger, accounts payable, accounts receivable, project costing, procurement, and other financial systems. In connection with the implementation, internal controls over financial reporting were updated to accommodate modifications to business processes and to leverage enhanced automated controls provided by the new system. There are inherent risks associated with implementing software changes and management believes its controls in the affected areas, as modified, continue to be designed appropriately and operate effectively. There have been no other 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, 2010, 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, 2010. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*. Based on this assessment, our management believes that, as of December 31, 2010, 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, 2010, 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, 2010, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2010, of the Partnership and our report dated February 18, 2011 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP
Houston, Texas
February 18, 2011

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

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:

Name	Age	Position
Rolf A. Gafvert	57	Chief Executive Officer, President and Director
Jamie L. Buskill	46	Chief Financial Officer, Senior Vice President and Treasurer
Brian A. Cody	53	Chief Operating Officer, Senior Vice President
Michael E. McMahon	55	Senior Vice President, General Counsel and Secretary
Arthur L. Rebell	70	Director, Chairman of the Board
Kenneth I. Siegel	53	Director
William R. Cordes	62	Director
Thomas E. Hyland	65	Director
Jonathan E. Nathanson	49	Director
Mark L. Shapiro	66	Director
Andrew H. Tisch	61	Director

All directors have served since 2005 except for Mr. Cordes and Mr. Siegel who were elected to the Board in 2006 and 2009, respectively. All directors serve until replaced or upon their voluntary resignation. The Board has begun a review of succession planning with respect to the Partnership's senior executive officers. In this connection, Mr. Gafvert has indicated to the Board his intention to retire within the next two years, although he has not set any firm date for his retirement.

Rolf A. Gafvert—Mr. Gafvert has been the Chief Executive Officer (CEO) of BGL since February 2007 and President since February 2008. Prior thereto he had been the Co-President of BGL since its inception in 2005. Mr. Gafvert has been the President of Gulf South since 2000 and has been employed by Gulf South or its predecessors since 1993. Mr. Gafvert is on the Board of Directors of the Interstate Natural Gas Association of America. Mr. Gafvert was selected to serve as a director on our Board due to his depth of knowledge of the Partnership, including its strategies, operations, supply sources and markets, his acute business judgment, his extensive knowledge of the natural gas pipeline industry and his position with the Partnership.

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 Chief Operating Officer of BGL since 2009. Prior to the appointment, Mr. Cody had been the Chief Commercial Officer of BGL since March 2007. Prior thereto he had 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 committees of the Interstate Natural Gas Association of America and the American Gas Association.

Arthur L. Rebell—Mr. Rebell was a Senior Vice President of Loews from 1998 until his retirement in June 2010. He also serves as a director of Diamond Offshore Drilling, Inc., a subsidiary of Loews. 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 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.

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.

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.

Jonathan E. Nathanson—Mr. Nathanson has been employed as Vice President—Corporate Development of Loews since 2001. Mr. Nathanson brings to the Board his significant industry experience as well as his familiarity with the

Partnership through 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.

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. Gafvert, 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 Conduct

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 2010, 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 long and short 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 similarly-sized 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 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 2010, approximately 60% of the total 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 2010 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 2010 results which significantly impacted the Board's compensation decisions included the following: we operated safe pipeline systems; we successfully completed several growth capital projects on time or ahead of schedule and at a total cost that was approximately $350 million less than our previous forecast; by the end of the year, all of our expansion pipelines were operating at design capacities; and we increased our cash distribution each quarter. However, our distributable cash of $448.5 million for the 2010 period was slightly lower than expected, primarily driven by the effects of narrowing price differentials between receipt and delivery points on our pipeline systems. 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 were, on average, approximately 10% higher than the target amounts set earlier in 2010.

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

Overview of Compensation Elements

During 2010, we established a new annual cash incentive plan, the Short-Term Incentive Plan (STIP), which is applicable to all exempt employees including our Named Executive Officers, and a new long-term cash and equity-based compensation plan, the Unit Appreciation Rights and Cash Bonus Plan (UAR and Cash Bonus Plan), which is applicable to selected employees including our Named Executive Officers. We previously made grants to our Named Executive Officers of phantom common units (Phantom Common Units) under our Long-Term Incentive Plan (LTIP) and phantom general partner units (Phantom GP Units) under our Strategic Long-Term Incentive Plan (SLTIP). The UAR and Cash Bonus Plan was intended to replace our SLTIP, under which we had granted substantially all available awards. We do not intend to make additional awards to our Named Executive Officers or other employees, under our LTIP or our SLTIP. We expect to continue our use of the LTIP to provide annual awards of common units to certain members of our Board, as described below under *Director Compensation*.

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

- base salary;
- annual cash Short-Term Incentive Award (STI Award) under our STIP;
- annual grant of Unit Appreciation Rights (UARs) and Cash Bonus (Long-Term Cash Bonus) under our UAR and Cash Bonus Plan; and
- retirement, medical and related benefits.

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

<u>*Base Salary*</u>

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 are competitive with comparable companies for the skills, experience and requirements of similar positions in order to attract and retain top talent. To achieve this goal, we have generally sought to provide base salaries that fall near the market median for similarly-sized, energy-related companies, which we believe supports competitive compensation and ensures retention. In order to ensure that each officer is appropriately compensated, when setting base salaries, the Board generally takes into consideration the responsibilities of each Named Executive Officer and determines compensation appropriate for the positions held and services to be rendered during the year.

The base salaries of our Named Executive Officers were not changed during 2009 or 2010, with the exception in 2009 of Mr. Cody, who received a salary adjustment in connection with his promotion to Chief Operating Officer. However, after our review of the 2010 Towers Watson U.S. Compensation Data Bank Energy Services Executive Database (Towers Database) and giving consideration to our not providing salary increases over a two-year period, the Board determined it would be appropriate to increase base salaries effective January 1, 2011. In determining the amount of the increases, the existing base salary amounts were compared with the market median shown in the Towers Database. The Board determined it was appropriate to increase base salaries to amounts that were closer to the market median to further our retention efforts with respect to these key employees. Accordingly, the base salary of Mr. Gafvert was increased by 31% and the base salaries of Messrs. Buskill, Cody and McMahon were increased by amounts ranging from 8% to 18%.

<u>*Incentive Compensation*</u>

Our incentive compensation program is comprised of two components – annual cash incentive awards under our STIP and long-term, cash and equity-based awards under our UAR and Cash Bonus Plan. The compensation awarded under these plans is discretionary. 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, 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. 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 2010, 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 service;
- Deliver strong financial performance as measured by key financial metrics including distributable cash, return on investment and EBITDA;
- Successfully complete capital projects in a timely and cost effective manner;
- Utilize Boardwalk's assets to improve operating efficiencies and maximize growth opportunities;
- Successfully renegotiate or remarket existing contracts that are terminating; and
- Pursue growth projects, while managing risk, allowing for the long-term stable growth of distributions to our investors.

As discussed under *Executive Summary*, in light of the achievements of our Partnership in 2010, the Board determined that we met a significant portion of our Partnership Performance Goals. 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. In light of these considerations, the Board approved the payout of STI Awards for each Named Executive Officer that were, on average, approximately 10% higher than the target amounts.

Long-Term Incentive Awards - UARs and Long-Term Cash Bonuses. We grant UARs and Long-Term Cash Bonus awards under our UAR and Cash Bonus Plan to encourage superior performance, attract and retain employees who are essential for our growth and profitability and to encourage those employees to devote their best efforts to advancing our business over both long and short-term time horizons. For 2010, approximately 70% of the value of our long-term incentive compensation was awarded in the form of UARs, with the remainder awarded as Long-Term Cash Bonus awards. We believe that this mix supports our compensation strategy. In particular, providing a higher percentage of the award as UARs serves to better align the interests of our Named Executive Officers with our unitholders over the long-term. In determining the size of the long-term incentive awards granted in 2010, we referred to the Towers Database to assess the reasonableness of the grants in relation to the market median value.

UARs – As a result of our structure as a limited partnership, our Named Executive Officers would be subject to significant adverse individual tax consequences if they owned our units directly. For example, direct ownership of our units would result in our Named Executive Officers being taxed on all income as partners rather than employees. Furthermore, direct ownership of units by our executives would negatively impact the tax status of our benefit plans. As a result, we award our Named Executive Officers UARs, the economic value of which is directly tied to the value of our common units but which are payable in cash. UARs do not confer any rights of equity ownership to the grantee. In 2010, the UARs were granted subject to a three-year vesting period tied to continued service, which we believe serves to align the longer-term interests of our Named Executive Officers with those of our unitholders as well as furthers our retention efforts.

Long-Term Cash Bonuses – We also grant long-term cash-based compensation awards, which mainly serve as retention awards. These Long-Term Cash Bonus awards are granted subject to a three-year vesting requirement that is tied to continued service. At the end of the vesting period, our Named Executive Officers that continue to be our employees are entitled to receive cash in the amount of the grant. In 2010, Long-Term Cash Bonuses were granted to Messrs. Gafvert, Buskill, Cody and McMahon in the amounts of $270,000, $150,000, $150,000 and $97,500, which amounts are not reflected in the Summary Compensation Table. If our Named Executive Officers continue to be employed with us at the end of the three-year period, then the awards will vest and be paid in full, and will be included in the Summary Compensation Table for that year.

If the holder of a UAR or Long-Term Cash Bonus award ceases to be employed during the restricted vesting period, all unvested awards held by that person will be cancelled and will not vest or be paid, except in limited circumstances described in the UAR and Cash Bonus Plan. See *Potential Payments Upon Termination or Change of Control* for more information regarding the terms of the UARs and Long-Term Cash Bonuses.

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, while one participates in a defined benefit cash balance pension plan available to employees of Texas Gas hired prior to November 1, 2006, which 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 November 1, 2006.

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 UARs and, prior to 2010, grants of Phantom Common Units and Phantom GP Units. Although no additional grants of Phantom Common Units and 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 2010.

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
Rolf A. Gafvert
Thomas E. Hyland
Jonathan E. Nathanson
Arthur L. Rebell, Chairman
Kenneth I. Siegel
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. Gafvert, have been or are officers or employees of us or our subsidiaries. Mr. Gafvert 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 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 2010, 2009 or 2008.

Executive Compensation

Summary of Executive Compensation

The following table shows a summary of total compensation earned by our Named Executive Officers during 2010, 2009 and 2008:

Summary Compensation Table for 2010

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 (9) ($)
Rolf A. Gafvert, CEO								
	2010	**325,000**	**500,000**	**247,706**	-	-	**35,202 (4)**	**1,107,908**
	2009	337,500	450,000	-	-	-	33,842	821,342
	2008	325,000	300,000	-	1,424,997	-	33,589	2,083,586
Jamie L. Buskill, CFO								
	2010	**300,000**	**275,000**	**137,614**	-	**103,533 (5)**	**17,085 (6)**	**833,232**
	2009	311,538	275,000	-	-	91,527	17,085	695,150
	2008	292,500	150,000	-	675,000	43,464	23,934	1,184,898
Brian A. Cody, Chief Operating Officer								
	2010	**255,000**	**275,000**	**137,614**	-	-	**27,216 (7)**	**694,830**
	2009	262,500	300,000	-	-	-	28,118	590,618
	2008	240,000	200,000	-	675,000	-	27,615	1,142,615
Michael E. McMahon, Senior Vice President, General Counsel and Secretary								
	2010	**240,000**	**275,000**	**89,447**	-	-	**28,298 (8)**	**632,745**
	2009	249,231	275,000	-	-	-	26,928	551,159
	2008	230,769	200,000	-	650,000	-	20,666	1,101,435

(1) The payroll cycle contained one additional pay period in 2009 as compared to 2010 and 2008.

(2) The amounts shown in this column represent cash STI Awards earned under our STIP for 2010 and annual bonus payments earned for 2009 and 2008.

(3) The amounts reflected in this column 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 and Phantom GP Units granted under our LTIP and SLTIP. Note 9 in Item 8 of this Report contains information regarding the assumptions we made in determining these values.

(4) Includes matching contributions under 401(k) plan ($14,700), employer contributions to the Gulf South Money Purchase Plan, club memberships, imputed life insurance premiums, travel clubs, preferred parking and spouse travel.

(5) Includes the change in qualified retirement plan account balance ($51,807) and interest and pay credits for the supplemental retirement plan ($51,726).

(6) Includes matching contributions under 401(k) plan ($14,700), imputed life insurance premiums and preferred parking.

(7) 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.

(8) Includes matching contributions under 401(k) plan ($14,700), employer contributions to the Gulf South Money Purchase Plan, imputed life insurance premiums, preferred parking and travel clubs.

(9) In addition to the compensation reportable herein, 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 be paid, subject to the terms of the plan and grant agreements, upon the expiration of a three year restricted period. 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:

Named Executive Officer	Year	Percentage of Total Compensation Paid as Salary and Bonus
Rolf A. Gafvert	**2010**	**74%**
	2009	96%
	2008	30%
Jamie L. Buskill	**2010**	**69%**
	2009	84%
	2008	37%
Brian A. Cody	**2010**	**76%**
	2009	95%
	2008	39%
Michael E. McMahon	**2010**	**81%**
	2009	95%
	2008	39%

In 2009, no long-term, equity-based awards were granted to our NEOs. As a result, the percentage of total compensation paid as salary and bonus was higher in 2009 than in 2010 or 2008.

Grants of Plan-Based Awards

The following table displays information regarding grants made during 2010 to our Named Executive Officers of plan-based awards under our UAR and Cash Bonus Plan:

Grants of Plan-Based Awards for 2010

Names	Grant Date	**All Other Stock Awards: Number of Shares of Stock or Units (#)**	**All Other Options Awards: Number of Securities Underlying Options (1) (#)**	**Exercise or Base Price of Option Awards (2) ($)**	**Grant Date Fair Value of Stock and Option Awards (3) ($)**
Rolf A. Gafvert	12/16/10	-	59,886	30.36	247,706
Jamie L. Buskill	12/16/10	-	33,270	30.36	137,614
Brian A. Cody	12/16/10	-	33,270	30.36	137,614
Michael E. McMahon	12/16/10	-	21,625	30.36	89,447

(1) Represents UARs granted under our UAR and Cash Bonus Plan. The exercise price for each UAR is equal to the closing price of our common units on the New York Stock Exchange on December 15, 2010. These UARs will vest upon the expiration of a three year restricted period, subject to the terms of the plan and grant agreements. Any amount payable to a holder of a UAR granted in 2010, after the expiration of the restricted period, is limited to a UAR Cap of $15.76.
(2) 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.
(3) Note 9 in Item 8 or this Report contains information regarding the grant date fair value of the UARs.

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

On December 16, 2010, our Board approved our UAR and Cash Bonus Plan, under which we have granted UARs to each of our Named Executive Officers. In previous years, our Board made grants of Phantom Common Units under our LTIP and Phantom GP Units under our SLTIP. No awards were granted to our Named Executive Officers under the LTIP or SLTIP in 2009 or 2010 and we do not plan to make additional grants to employees under those plans. 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.

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, limited to the applicable dollar cap amount per UAR (UAR Cap). 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).

Phantom Common Units. Each outstanding Phantom Common Unit includes a tandem grant of Distribution Equivalent Rights (DERs); vests 50% on the second anniversary date of the grant date and 50% on the third anniversary date of the grant date, and will be payable to the grantee in cash 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 plus the vested amount then credited to the grantee's DER account.

Phantom GP Units. A Phantom GP Unit provides the holder with an opportunity, subject to vesting, to receive a lump sum cash payment in an amount determined as the lesser of $50,000, or the product of (1) the quotient of (i) cash distributions made to our general partner during the four consecutive calendar quarters prior to the vesting date, divided by (ii) the current yield on the units, multiplied by (2) .0001. The vesting period of the Phantom GP Units granted to our Named Executive Officers is 4.0 years from the initial date of grant.

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, 2010:

Outstanding Equity Awards at December 31, 2010

	Option/UAR Awards			Stock Awards			
	UARs			Phantom Common Units		Phantom GP Units	
Name	Number of Securities Underlying Unexercised Unearned Options/UARs	Option/UAR Exercise Price ($)	Option/UAR Expiration Date	Number of Shares or Units That Have Not Vested	Market Value of Shares or Units of Stock That Have Not Vested (3) ($)	Number of Shares or Units of Stock That Have Not Vested	Market Value of Shares or Units of Stock That Have Not Vested (4) ($)
Rolf A. Gafvert	59,886	30.36 (1)	(2)	4,357	135,633	75	3,094,325
Jamie L. Buskill	33,270	30.36 (1)	(2)	1,867	58,120	34	1,402,761
Brian A. Cody	33,270	30.36 (1)	(2)	1,867	58,120	37	1,526,534
Michael E. McMahon	21,625	30.36 (1)	(2)	1,245	38,757	33	1,361,503

(1) The exercise price for each UAR granted in 2010 is $30.36, the closing price of our common units on the New York Stock Exchange on December 15, 2010. A UAR cap of $15.76 was established for each UAR award granted and each UAR includes a DER Adjustment. Note 9 in Item 8 of this Report contains more information regarding our UAR and Cash Bonus Plan.
(2) The UARs will vest and become payable in cash to each Named Executive Officer upon the expiration of a three-year restricted period, or December 16, 2013, for grants made in 2010.
(3) The market value reported is based on the NYSE closing market price on December 31, 2010 of $31.13. In addition to the Phantom Common Units, Messrs. Gafvert, Buskill, Cody and McMahon have accumulated non-vested amounts related to DERs that are tandem grants to the Phantom Common Units. Such DER amounts for Messrs. Gafvert, Buskill, Cody, and McMahon were $17,341, $7,431, $7,431 and $4,955 as of December 31, 2010. The Phantom Common Units will vest on December 16, 2011. Note 9 in Item 8 of this Report contains more information regarding our LTIP.
(4) The market value reported is based on the NYSE closing market price on December 31, 2010 of $31.13 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 2010 of Phantom Common Units and Phantom GP Units previously granted to our Named Executive Officers.

Option Exercises and Stock Vested for 2010

	Stock Awards			
Name	**Number of LTIP Awards Vesting (#)**	**Value Received on Vesting (1) ($)**	**Number of SLTIP Awards Vesting (#)**	**Value Received on Vesting (2) ($)**
Rolf A. Gafvert	7,624	268,242	25	793,997
Jamie L. Buskill	1,868	63,811	12	381,119
Brian A. Cody	3,501	123,497	12	381,119
Michael E. McMahon	2,878	102,215	10	317,599

(1) The LTIP awards (Phantom Common Units) vested in December 2010 and were paid out in a lump sum in January 2011. At no time were units issued to or owned by the Named Executive Officers.
(2) The SLTIP awards (Phantom GP Units) vested in February 2010 and were paid out in a lump sum in March 2010. 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. Gafvert, Cody and McMahon are, and during 2010 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 2010

Name	**Plan Name**	**Number of Years Credited Service (#)**	**Present Value of Accumulated Benefit ($)**	**Payments During Last Fiscal Year ($)**
Jamie L. Buskill	TGRP	24.3	294,362	-
	SRP	24.3	152,292	-

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 five 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 2010. 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, 2010, commencing in 2011, 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, 2010, 2009 and 2008 were 4.19%, 4.27% and 4.27% and for future years, 3.77%, 4.19% and 4.27%. The future normal retirement date accumulated cash balance was then discounted using an interest rate at December 31, 2010, 2009 and 2008 of 5.00%, 5.70% and 6.30%. The increase in the present value of accumulated benefit for the TGRP between December 31, 2010 and 2009 of $51,807 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 2010 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, 2010 and 2009, of $51,726, 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 any of our Named Executive Officers, although they are eligible to receive accelerated vesting of cash and equity-based awards under certain of our compensation plans. We have made grants of UARs, Long-Term Cash Bonuses, Phantom Common Units and Phantom GP Units to each of our executives subject to specific vesting schedules and payment limitations, as discussed above. The Long-Term Cash bonuses and UARs will vest on a prorated basis under certain circumstances and will be payable in accordance with the plan provisions, as described below. The Phantom Common Units and 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. These plan distributions will be no more than those amounts disclosed in the tables above, and such amounts will be paid only once in accordance with the terms of the applicable plan; thus, the table 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, as 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. Executive officers at 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.

Unit Appreciation Rights and Cash Bonus Plan. The outstanding UARs and Long-Term Cash Bonuses vest and are payable upon the lapsing of a three-year restricted period. A change of control would not automatically affect the vesting or payment of the UARs and Long-Term Cash Bonuses. 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.

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. Termination by us without cause at least two years after the date of grant of the award would cause unvested UARs and Long-Term Cash Bonuses to become vested on a prorated basis based on the date of the termination. 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. The award agreements define retirement as a termination on or after age 55 with at least 10 years of continuous service with us. 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. In the cases of death or disability or involuntary termination of employment, the value of any then vested awards would be determined and paid at the time of termination. In the case of retirement, the value of any then vested awards would be determined and paid on the original scheduled payment date. Unvested UARs or Long-Term Cash Bonuses would be forfeited upon voluntary termination of employment.

Long-Term Incentive Plan. All unvested Phantom Common Units (and all DERs associated with such Phantom Common Units) will become fully vested upon our change of control. 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 fully vested upon an executive's death, disability, retirement, or termination by us without cause. 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. 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 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, cause shall be defined similarly to the term defined above for UARs and Long-Term Cash Bonuses.

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. As our general partner met its minimum distribution amount for 2010, 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, 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 by our general partner other than for cause. The SLTIP definition for each of these terms is substantially similar to the definitions for the LTIP terms described above.

Paid Time Off (*PTO).* The Named Executive Officers will receive the remaining accrued paid time off that they accumulated during the 2010 year, plus up to a maximum of five days carried forward from a previous year.

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, 2010. The closing price of our common units on the NYSE on December 31, 2010, $31.13, 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.

Potential Payments Upon Termination or Change of Control at December 31, 2010

Name	Plan Name	Change of Control (1) ($)	Termination Other than for Cause ($)	Termination for Cause, or Voluntary Resignation ($)	Retirement (2) ($)	Death or Disability ($)
Rolf A. Gafvert	UAR and Cash Bonus Plan (3)	-	-	-	6,429	6,429
	LTIP (4)	152,974	152,974	-	-	152,974
	SLTIP (5)	3,094,325	3,094,325	-	-	3,094,325
	PTO (6)	-	-	-	-	-
	Total	3,247,299	3,247,299	-	6,429	3,253,728
Jamie L. Buskill (7)	UAR and Cash Bonus Plan (3)	-	-	-	-	3,572
	LTIP (4)	65,550	65,550	-	-	65,550
	SLTIP (5)	1,402,761	1,402,761	-	-	1,402,761
	PTO (6)	5,769	5,769	5,769	-	5,769
	Total	1,474,080	1,474,080	5,769	-	1,477,652
Brian A. Cody	UAR and Cash Bonus Plan (3)	-	-	-	-	3,572
	LTIP (4)	65,550	65,550	-	-	65,550
	SLTIP (5)	1,526,534	1,526,534	-	-	1,526,534
	PTO (6)	-	-	-	-	-
	Total	1,592,084	1,592,084	-	-	1,595,656
Michael E. McMahon	UAR and Cash Bonus Plan (3)	-	-	-	2,322	2,322
	LTIP (4)	43,712	43,712	-	-	43,712
	SLTIP (5)	1,361,503	1,361,503	-	-	1,361,503
	PTO (6)	4,615	4,615	4,615	-	4,615
	Total	1,409,830	1,409,830	4,615	2,322	1,412,152

(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) Retirement age is defined under the UAR and Cash Bonus Plan as age 55 with at least 10 years of continuous service with us, and for the LTIP and SLTIP as age 65 or older, although a participant in the LTIP and SLTIP can become fully vested in outstanding awards at age 60 with Board approval. Retirement of a participant prior to age 55 with 10 years of continuous service under the UAR and Cash Bonus Plan or age 60 in the case of the LTIP and SLTIP would result in the forfeiture of any outstanding awards. As of

December 31, 2010, Messrs. Gafvert and McMahon were eligible for retirement as defined in the UAR and Cash Bonus Plan. None of the named executive officers were eligible for retirement as defined in the LTIP and 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, 2010, 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 factor was 0.015 at December 31. No cash distributions were paid on behalf of our common units for the period the UARs were outstanding, therefore no DER Adjustment was applied to the exercise price. The excess of the closing price of our common units on December 31, 2010 over the exercise price of $30.36, or $0.77, was below the UAR Cap of $15.76. As of December 31, 2010, Messrs. Gafvert, Buskill, Cody and McMahon held UARs of 59,886, 33,270, 33,270 and 21,625 and Long-Term Cash Bonuses of $270,000, $150,000, $150,000 and $97,500 respectively.

(4) LTIP amounts were determined by multiplying the number of unvested Phantom Common Units each executive held on December 31, 2010, by the value of our common units on that date, or $31.13. The resulting number was then added to the value of the DERs that were associated with the accelerated Phantom Common Units. As of December 31, 2010, Messrs. Gafvert, Buskill, Cody and McMahon held Phantom Common Units of 4,357, 1,867, 1,867 and 1,245, respectively. The amount of DERs accrued for these units were for Messrs. Gafvert, Buskill, Cody and McMahon, $17,341, $7,431, $7,431 and $4,955, respectively.

(5) SLTIP amounts were determined by multiplying the number of unvested Phantom GP Units each executive held on December 31, 2010, 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, 2010, of $27.3 million and an implied yield on our common units of 6.62% at December 31, 2010. As of December 31, 2010, Messrs. Gafvert, Buskill, Cody and McMahon held 75, 34, 37, and 33 Phantom GP Units, respectively.

(6) Includes earned but unused paid time off at December 31, 2010.

(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 2010:

Director Compensation for 2010

Name	Fees Earned or Paid in Cash ($)	Stock Awards (1) ($)	Total ($)
Arthur L. Rebell	22,417	9,002	31,419
William R. Cordes	41,000	14,525	55,525
Thomas E. Hyland (2)	48,000	14,525	62,525
Mark L. Shapiro	41,000	14,525	55,525

(1) In 2010, Mr. Rebell retired from employment with Loews and became an Eligible Director at that time. On August 5, 2010, Mr. Rebell was awarded 292 common units, which amount was prorated based on the portion of the year that he was an Eligible Director. The total grant date fair value of the award, based on the closing market price of $30.83, was $9,002. On May 6, 2010, Messrs. 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 $29.05, was $14,525.

(2) Chairman of the Audit Committee.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information, at February 18, 2011, 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
Jamie L. Buskill	-	-	-	-	-
Brian A. Cody	-	-	-	-	-
William R. Cordes	2,000	*	-	-	*
Rolf A. Gafvert	-	-	-	-	-
Thomas E. Hyland	7,900 (2)	*	-	-	*
Michael E. McMahon	-	-	-	-	-
Jonathan E. Nathanson	15,000	*	-	-	*
Arthur L. Rebell	39,375 (3)	*	-	-	*
Mark L. Shapiro	12,500	*	-	-	*
Kenneth I. Siegel	-	-	-	-	-
Andrew H. Tisch	81,050 (4)	*	-	-	*
All directors and executive officers as a group	157,825	*	-	-	-
BPHC (5)	102,719,466	61%	22,866,667	100%	65%
Loews Corporation (5)	102,719,466	61%	22,866,667	100%	65%

*Represents less than 1% of the outstanding common units

(1) As of February 18, 2011, we had 169,721,916 common units and 22,866,667 class B units issued and outstanding.

(2) 400 of these units are owned by Mr. Hyland's spouse.

(3) 32,984 of these units are owned by ARebell, LLC, a limited liability company controlled by Mr. Rebell.

(4) 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.

(5) 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 incentive distribution rights. Including the general partner interest but excluding the impact of the incentive distribution rights, Loews indirectly owns approximately 66% 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, 2010, 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	**3,517,708**

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 2010 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 2010 and 2009 by category as described in the notes to the table (in millions):

	2010	2009
Audit fees (1)	**$ 2.0**	$ 2.0
Audit related fees (2)	**0.2**	0.1
Total	**$ 2.2**	$ 2.1

(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 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, 2010 and 2009

Consolidated Statements of Income for the years ended December 31, 2010, 2009 and 2008

Consolidated Statements of Cash Flows for the years ended December 31, 2010, 2009 and 2008

Consolidated Statements of Changes in Partners' Capital for the years ended December 31, 2010, 2009 and 2008

Consolidated Statements of Comprehensive Income for the years ended December 31, 2010, 2009 and 2008

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, 2010, 2009 and 2008 and are not included in specific schedules herein. These amounts have been deducted from the respective assets on the Consolidated Balance Sheets (in millions):

		Additions:			
Description	**Balance at Beginning of Period**	**Charged to Costs and Expenses**	**Other Additions**	**Deductions**	**Balance at End of Period**
Allowance for doubtful accounts:					
2010	**$ 0.3**	**$ 0.4**	**$ -**	**$ (0.1)**	**$ 0.6**
2009	0.3	0.3	-	(0.3)	0.3
2008	0.4	-	(0.1)	-	0.3
Inventory obsolescence:					
2010	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
2009	-	-	-	-	-
2008	0.1	-	-	(0.1)	-

(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).
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 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).

4.13 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).

4.14 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 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)

**10.6 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).

**10.7 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).

**10.8 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).

**10.9 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).

**10.10 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).

**10.11 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).

**10.12 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).

10.13 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).

*21.1 List of Subsidiaries of the Registrant.

*23.1 Consent Of Independent Registered Public Accounting Firm.

*31.1 Certification of Rolf A. Gafvert, 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 Rolf A. Gafvert, 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 10.9 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 18, 2011 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 18, 2011	/s/ *Rolf A. Gafvert* Rolf A. Gafvert President, Chief Executive Officer and Director (principal executive officer)
Dated: February 18, 2011	/s/ *Jamie L. Buskill* Jamie L. Buskill Senior Vice President, Chief Financial Officer and Treasurer (principal financial officer)
Dated: February 18, 2011	/s/ *Steven A. Barkauskas* Steven A. Barkauskas Senior Vice President, Controller and Chief Accounting Officer (principal accounting officer)
Dated: February 18, 2011	/s/ *William R. Cordes* William R. Cordes Director
Dated: February 18, 2011	/s/ *Thomas E. Hyland* Thomas E. Hyland Director
Dated: February 18, 2011	/s/ *Jonathan E. Nathanson* Jonathan E. Nathanson Director
Dated: February 18, 2011	/s/ *Arthur L. Rebell* Arthur L. Rebell Director
Dated: February 18, 2011	/s/ *Mark L. Shapiro* Mark L. Shapiro Director
Dated: February 18, 2011	/s/ *Kenneth I. Siegel* Kenneth I. Siegel Director
Dated: February 18, 2011	/s/ *Andrew H. Tisch* Andrew H. Tisch Director

EXHIBIT 21.1

BOARDWALK PIPELINE PARTNERS, LP
Subsidiaries of the Registrant
December 31, 2010

Name of Subsidiary	Organized Under Laws of	Business Names
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

EXHIBIT 23.1

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 18, 2011, 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, 2010.

/s/ Deloitte & Touche LLP
Houston, Texas
February 18, 2011

EXHIBIT 31.1

I, Rolf A. Gafvert, 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 18, 2011

/s/ Rolf A. Gafvert
Rolf A. Gafvert
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 18, 2011

/s/ Jamie L. Buskill

Jamie L. Buskill

Senior Vice President, Chief Financial Officer and Treasurer

EXHIBIT 32.1

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, 2010, (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 18, 2011

/s/ Rolf A. Gafvert
Rolf A. Gafvert
President, Chief Executive Officer and Director
(principal executive officer)

EXHIBIT 32.2

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, 2010, (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 18, 2011

/s/ Jamie L. Buskill
Jamie L. Buskill
Senior Vice President, Chief Financial Officer and Treasurer
(principal financial officer)