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, 2009

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 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 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 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, 2009, was approximately $1.1 billion. As of February 10, 2010, the registrant had 169,721,916 common units outstanding and 22,866,667 Class B units outstanding.

Documents incorporated by reference. None.

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2009 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 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). Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews), owns 114.2 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 72% 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 marketers, local distribution companies (LDCs), producers, electric power generators, interstate and intrastate pipelines 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, 2009, approximately 74% 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 11% 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 Phase III of the Western Kentucky Storage Expansion project 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 2009, our pipeline systems transported approximately 2.1 trillion cubic feet (Tcf) of gas. Average daily throughput on our pipeline systems during 2009 was approximately 5.7 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 163.0 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 Agua Dulce and Carthage, Texas. 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 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 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.

Recent Expansion and Growth Projects: In 2008 and 2009, we completed our East Texas Pipeline, Southeast Expansion and our Gulf Crossing Project (42-inch expansion project pipelines), which collectively consist of approximately 700 miles of 42-inch pipeline and certain related compression facilities. We also completed and placed in service our Fayetteville and Greenville Laterals, which together consist of approximately 260 miles of 36-inch pipeline and certain related compression facilities. Additional compression was placed into service on our Fayetteville and Greenville Laterals in January 2010 and we expect to place into service additional compression on our Gulf Crossing Project in the first quarter 2010. With the exception of our Greenville Lateral, these projects were designed to operate at higher than normal operating pressures. While completing the requirements to operate our 42-inch expansion project pipelines and the Fayetteville Lateral at higher than normal operating pressures in 2009, we discovered anomalies in certain pipeline segments on each of the projects, which resulted in reductions of operating pressures on these pipelines below normal operating pressures and the shut down of segments of the pipelines for periods of time to remediate the anomalies. Item 7, *Management's Discussion and Analysis of Financial Condition and Results of Operations* contains further information. We are currently engaged in the Haynesville and Clarence Compression Projects.

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 transportation service (NNS). 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. The market area directly served by Texas Gas 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 requirements during winter months.

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 NNS, which allows customers to borrow gas from storage during the winter season to be repaid in-kind during the following summer season. Texas Gas also offers summer no-notice transportation service (SNS), which is designed primarily to meet the needs of electrical power generation facilities during the summer season, and other firm and interruptible storage services.

The following table provides information for each of our operating subsidiaries as of December 31, 2009, except for average daily throughput which is for the year ended December 31, 2009:

Pipeline	Miles of Pipeline	Peak-day Delivery Capacity	Working Gas Storage Capacity	Average Daily Throughput
		(Bcf/d)	(Bcf)	(Bcf/d)
Gulf Crossing	360	1.4 (1)	-	0.7 (2)
Gulf South	7,700	6.2	83.0	3.1 (2)
Texas Gas	6,110	4.3	80.0	2.8 (2)

(1) The designated peak-day transmission capacity is expected to increase to 1.7 Bcf per day from the addition of compression, which is expected to be placed in service in the first quarter 2010.

(2) The average daily throughput was adversely impacted because we operated the pipeline expansion projects at reduced operating pressures and shut down segments of the pipelines for periods of time to remediate the pipe anomalies. *Expansion and Growth Projects*, in Item 7 of this Report, contains more information regarding the pipe anomalies and related remediation.

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 NNS and SNS. 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 NNS 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 a portion of its storage capacity.

No-Notice Service and Summer No-Notice Service. NNS and SNS 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 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 marketers, producers, LDCs, electric power generators, intrastate and interstate pipelines 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 marketers, producers and other third parties who provide transportation and storage services to end-users. Based on 2009 revenues, our customer mix was as follows: marketers (42%), producers (30%), LDCs (17%), power generators (4%), pipelines (2%) and industrial end users and others (5%). Based upon 2009 revenues, our deliveries were as follows: pipeline interconnects (54%), LDCs (22%), storage activities (11%), power generators (4%), industrial end-users (4%) and other (5%). One customer, Devon Energy Production Company, LP, accounted for approximately 11% of our 2009 operating revenues. Refer to Item 1A, *Risk Factors*, regarding risks associated with our customers.

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. Approximately 21% of the marketers are sponsored by LDCs and approximately 17% are sponsored by producers.

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 NNS. We serve approximately 183 LDCs at more than 300 delivery locations across our pipeline systems. The demand of these customers peaks during the winter heating season.

Power Generators. 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 SNS, firm and interruptible transportation services.

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

Industrial End Users. We provide approximately 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 supply and flexibility and reliability of service. Competition is particularly strong in the Midwest and Gulf Coast states where we compete with numerous existing pipelines, including the Rockies Express Pipeline that transports natural gas from northern Colorado to eastern Ohio and the Mid-Continent Express Pipeline that transports gas from Oklahoma and Texas to Alabama. We will also directly compete with several new pipeline projects that are proposed or under development, including projects originating in the Haynesville Shale area – more specifically, the Tiger Pipeline that will transport gas to Perryville, Louisiana and the Haynesville Extension Pipeline that will transport gas to the industrial complex in southeastern Louisiana - and the Fayetteville Express Pipeline which will originate in the Fayetteville Shale area and continue eastward to Mississippi. 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 and fuel oils.

The natural gas industry has built, or is in the process of completing, significant new pipeline infrastructure that will support the development of unconventional natural gas supply basins across the U.S. Additional pipeline infrastructure projects are being proposed. These new pipeline developments have increased competition in certain pipeline markets, resulting in lower price differentials between physical locations (basis spreads). Basis spreads can impact the rates we will be able to negotiate with our customers when contracts come up for renewal. Despite these competitive conditions, assuming that customers use all of their reserved capacity, substantially all of the operating capacity on our pipeline systems is contracted for with a weighted-average contract life of approximately 5.9 years, although each year a portion of our capacity becomes subject to re-contracting risk. For example approximately 14% of our contracts are due to expire in 2010.

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 occurred during the winter months driven by heating needs, the increased use of natural gas for cooling needs during the summer months has reduced the seasonality of our revenues over time. During 2009, approximately 55% of our revenues were recognized in the first and fourth quarters of the year.

Government Regulation

Federal Energy Regulatory Commission. FERC regulates our operating subsidiaries under the Natural Gas Act of 1938 (NGA) 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 gas transportation 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 approximately 8.3 Bcf of 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 allowed rate of return, throughput assumptions, the allocation of costs, the capital structure and the rate design. 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. Texas Gas is prohibited from placing new rates into effect prior to November 1, 2010, and neither Gulf South nor Texas Gas has an obligation to file a new rate case. Gulf Crossing will have to either file a rate case or justify its initial firm transportation rates by the end of the first quarter 2012.

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 our recently completed 42-inch pipeline expansion projects under special permits that will allow us to operate the pipelines at higher than normal operating pressures of up to 0.80 of the pipe's Specified Minimum Yield Strength (SMYS). We are seeking authority from PHMSA to operate our Fayetteville Lateral at higher than normal operating pressures. We will need to operate each of these pipelines at higher than normal operating pressures in order 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 these pipelines 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 March 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;

- 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, 2009, we had approximately 1,110 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 some of the more 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 and 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 need to obtain and maintain authority from PHMSA to operate at higher than normal operating pressures.

We have entered into firm transportation contracts with shippers which would utilize the maximum design capacity of our recently completed 42-inch pipeline expansion projects and our Fayetteville Lateral assuming that we operate those pipelines at higher than normal operating pressures (up to 0.80 SMYS), which increases the pipeline's peak-day transmission capacity from that available at normal operating pressures (up to 0.72 SMYS).

In December 2009, we received authority from PHMSA to operate our 42-inch pipeline expansion projects at higher than normal operating pressures. If PHMSA were to withdraw such authority we would not be able to transport all of our contracted quantities of natural gas on these pipelines, beginning in mid-2010, or we could incur additional costs to re-obtain such authority or seek alternate ways to meet our contractual obligations, any of which could have a material adverse affect on our business financial condition, results of operations and cash flows.

We are seeking authority from PHMSA to operate our Fayetteville Lateral at higher than normal operating pressures. Unless we obtain such authority from PHMSA, we will not be able to operate the Fayetteville Lateral at its anticipated peak-day transmission capacity, and beginning in mid-2011 we will not be able to transport all of the contracted for volumes on that pipeline. In addition, we have incurred and may continue to incur significant costs to inspect, test and remediate pipe segments on the Fayetteville Lateral in order to obtain, or maintain if granted, authority to operate at higher than normal operating pressures or to develop alternative ways to meet our contractual obligations, any of which could have a material adverse affect on our business, financial condition, results of operations and cash flows. PHMSA retains discretion as to whether to grant, or to maintain in force, authority to operate a pipeline at higher than normal operating pressures.

We may not be able to maintain or replace expiring gas transportation and storage contracts at favorable rates.

Our primary exposure to market risk occurs at the time existing transportation contracts expire and are subject to renegotiation. As of December 31, 2009, approximately 14% of the contracts for firm transportation capacity on our pipeline systems will expire during 2010. Upon expiration, we may not be able to extend contracts with existing customers or obtain replacement contracts at favorable rates or on a long-term basis. Key drivers that influence the rates that our customers are willing to pay for transportation is the price differential of natural gas between physical locations, which can be affected by, among other things, the availability and supply of natural gas, available capacity, storage inventories, weather and general market demand in the respective areas.

The extension or replacement of existing contracts depends on a number of factors beyond our control, including:

- existing and new competition to deliver natural gas to our markets;
- development of new supplies located near key markets;
- the growth in demand for natural gas in our markets;
- whether the market will continue to support long-term contracts;

- the current price differentials, or market price spreads between various receipt and delivery points on our pipelines; and
- the effects of state regulation on customer contracting practices.

Increased competition could result in lower contracted capacity on our pipelines, decreased rates for our services and reduced revenues.

We compete primarily with other interstate and intrastate pipelines in the transportation and storage of natural gas. Competition is particularly strong in the Midwest and Gulf Coast states where we compete with numerous existing pipelines, such as the Rockies Express Pipeline and the Mid-Continent Express Pipeline. We will also directly compete with several new pipeline projects that are proposed or under development, including projects originating in the Haynesville Shale area – more specifically, the Tiger Pipeline that will transport gas to Perryville, Louisiana and the Haynesville Extension Pipeline that will transport gas to the industrial complex in southeastern Louisiana - and the Fayetteville Express Pipeline which will originate in the Fayetteville Shale area and continue eastward to Mississippi. For new growth and expansion projects, we compete with other pipelines for contracts mainly with producers that would support such projects in order to transport their gas to market areas. At an industry level, the various natural gas supply areas compete against one another to reach optimal market areas, and natural gas, as a commodity, competes with other forms of energy available to our customers, including electricity, coal and fuel oils, and other alternative fuel resources.

Our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows could be adversely affected by competition or changing market conditions. The principle elements of competition among pipelines are availability of capacity, rates, terms of service, access to gas supplies, flexibility and reliability. FERC's policies promote competition in 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 force 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.

The regulatory program that applies to interstate pipelines is different than the regulatory program that applies to many of our competitors that are not regulated interstate pipelines. This difference in regulatory oversight can result in longer lead times to develop and complete a project when it is regulated at the federal level. We compete against a number of intrastate pipelines which have significant regulatory advantages over us because of the absence of FERC regulation. In view of potential rate advantages and construction and service flexibility available to intrastate pipelines, we may lose customers and throughput to intrastate competitors.

Continued development of new supply sources could impact demand.

The discovery of non-traditional natural gas production areas nearer to key market areas we access directly, or indirectly through third-party pipeline interconnects, 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 to supply volumes from the Marcellus Shale, gas from the Rocky Mountains, Canada and LNG import terminals may compete with and displace volumes from the Gulf Coast and Mid-Continent supply sources in order to serve the Northeast, Midwest and East Coast markets. The displacement of gas originating in supply areas connected to our pipeline systems by these new supply sources that are closer to the end-use markets could result in lower transportation revenues, which could have a material adverse impact on our business, financial condition, results of operations and cash flows.

We are undertaking and may continue to pursue complex pipeline or storage projects which involve significant risks that may adversely affect our business.

We have recently completed several pipeline expansion projects and we may also undertake additional pipeline or storage projects in the future. In pursuing previous projects, we have experienced significant cost overruns and we may experience cost increases in the future. We have also experienced delays in constructing and commissioning previous projects and may experience additional delays or cost increases in the future resulting from a variety of factors, including but not limited to the following:

- delays in obtaining regulatory approvals, including delays in receiving authorization from PHMSA to operate at higher than normal operating pressures under special permits;

- difficult construction conditions, including adverse weather conditions;

- delays in obtaining, or high demand for, key materials; and

- shortages of qualified labor and escalating costs of labor and materials resulting from the high level of construction activity in the pipeline industry.

In pursuing current or future projects, we could experience delays or cost increases for the reasons described above or as a result of other factors. We may not be able to complete our current or 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 revenues from our current or future projects sufficient to cover the costs associated with owning and operating these pipelines and to provide the benefits we had anticipated from the projects, which could have a material adverse effect on our business, financial condition, results of operations and cash flows, including our ability to make distributions to our unitholders.

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 NNS 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 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. For example, Devon Energy Production Company, LP represented over 11% of our 2009 revenues and we expect this customer to continue to account for more than 10% of our 2010 revenues. Additionally, we may be unable to negotiate extensions or replacements of contracts and key customers on favorable terms. The loss of all or even a portion of the contracted volumes of these customers, as a result of competition, creditworthiness or otherwise, could have a material adverse effect on our business, financial condition, operating revenues and cash flows.

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 that are beyond our control. These factors include:

- worldwide economic conditions;
- weather conditions, seasonal trends and hurricane disruptions;
- the relationship between the available supplies and the demand for natural gas;

- the availability of LNG;
- 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, LNG 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 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 cost of providing the service, the volumes of gas being transported, how costs are allocated 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. FERC recently challenged the rates of three non-affiliated pipelines. Such a challenge against us could adversely affect our ability to establish reasonable transportation rates, to charge rates that would cover future increases in our costs or even to continue to collect rates to maintain our current revenue levels that are designed to permit a reasonable opportunity to recover current costs and depreciation and earn a reasonable return. Additionally, FERC can propose changes or modifications to any of its existing rate-related policies.

If our subsidiaries were to file a rate case, or if we have to defend our 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 our subsidiaries 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 pipeline subsidiaries, 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. An adverse determination in any future rate proceeding brought by or against any of our subsidiaries could have a material adverse effect on our business.

Our natural gas transportation and storage operations are subject to extensive regulation by FERC, in addition to FERC rules and regulations related to the rates we can charge for our services.

FERC's regulatory authority extends to:

- operating terms and conditions of service;
- the types of services we may offer to our customers;
- construction of new facilities;
- creation, extension or abandonment of services or facilities;
- accounts and records; and
- relationships with certain types of affiliated companies involved in the natural gas business.

FERC's action in any of these areas or modifications of its current regulations can adversely impact our ability to compete for business, to construct new facilities, offer new services or to 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.

FERC regulates the type of services we can offer, the terms and conditions of those services and has authority to review pipeline contracts to ensure that the services, rates and charges are just and reasonable and not unduly discriminatory. FERC has various regulatory policies upon which it relies to protect against undue discrimination. One such policy is to monitor the terms and conditions of transportation service contracts for any material deviation from the pipeline's tariff. If FERC determines that a term of any such contract, at the time it is entered into or during the term of that agreement, deviates in a material manner from a pipeline's tariff, FERC can, among other potential remedies, order the pipeline to remove the term from the contract and execute and re-file a new contract with FERC, or alternatively, amend its tariff to include the deviating term, thereby offering it to all shippers. If FERC audits a pipeline's contracts or other aspects of our pipeline business and finds material deviations or other violations, FERC could conduct a formal enforcement investigation, resulting in penalties and/or ongoing compliance obligations.

Should we fail to comply with all applicable statutes, rules, regulations and orders administered or issued by FERC, we could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1.0 million per day for each violation.

We are subject to laws and regulations relating to the environment which may expose us to significant costs, liabilities and loss of revenues.

Our operations are 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 or future environmental regulations could require significant expenditures and the failure to comply with current or future regulations might result in the imposition of fines and penalties. Current rate structures, customer contracts and prevailing market conditions might not allow us to recover the additional costs incurred to comply with new environmental requirements and we might not be able to obtain or maintain all required environmental regulatory approvals for certain projects. If there is a delay in obtaining any required environmental regulatory approvals or if we fail to obtain and comply with them, we may be required to shut down certain facilities or become subject to additional costs.

We face risks associated with global climate change.

Governments around the world are beginning to address climate change issues. Beginning in March 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. In December 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. 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.

It is anticipated that 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.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations or result in increased costs.

We obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties and governmental agencies for a specific period of time. As a result, we are subject to the risk of increased costs to maintain necessary use of land in accordance with the agreements that convey to us those rights. Additionally, if we do not comply with the terms of those agreements, our rights could be restricted which could disrupt our operations.

We are subject to strict safety regulations which may impose significant costs and liabilities on us.

Under PHMSA regulations, we are required 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. The 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.

We are also subject to the requirements of the Occupational Safety and Health Act (OSHA) and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local governmental authorities and local residents.

Should we fail to comply with PHMSA regulations, OSHA or state statutes and general industry standards regulating the protection of the health and safety of workers, or keep adequate records or monitor pipeline integrity or occupational exposure to regulated substances, we could be subject to penalties and fines and/or otherwise incur significant costs to restore compliance.

***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 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.

We are subject to litigation.

We are subject to litigation in the normal course of business. Litigation is costly and time consuming to defend and could result in material expense. For a discussion of our current legal proceedings, see Note 3 in Item 8 of this Report.

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. These developments have subjected our operations to increased risks and could have a material adverse effect on our business. In particular, we might experience increased capital or operating costs to implement increased security.

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.

At December 31, 2009, BPHC, a subsidiary of Loews, owned a majority of our limited partner interests 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.
- 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 could 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.

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. 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. 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 Department of the Treasury and the IRS 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. Although existing publicly traded partnerships are entitled to rely on these proposed Treasury Regulations, they are not binding on the IRS and are subject to change until final Treasury Regulations are issued.

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.

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 103,000 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 on our material property, including our pipelines and storage facilities.

Item 3. Legal Proceedings

For a discussion of certain of our current legal proceedings, see Note 3 in Item 8 of this Report.

Item 4. Submission of Matters to a Vote of Security Holders

None.

PART II

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

Our Partnership Interests

As of December 31, 2009, 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 114.2 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 72% of our equity interests. 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 10, 2010, we had 169.7 million common units outstanding held by approximately 60 holders of record. BPHC owns 114.2 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 10, 2010, was $30.03 per unit.

	Sales Price Range per Common Unit		Cash Distributions per Common Unit (1) (2)
	High	Low	
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**
Year ended December 31, 2008:			
Fourth quarter	$ 25.97	$ 14.00	$ 0.480
Third quarter	24.96	17.11	0.475
Second quarter	28.65	23.34	0.470
First quarter	32.25	21.24	0.465

(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, beginning with the distribution attributable to the third quarter 2008. 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 2009, 2008 and 2007, we paid $13.3 million, $7.5 million and $2.5 million in distributions on behalf of our IDRs.

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, 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 summary historical financial and operating data for us and our predecessor Boardwalk Pipelines, as of the dates and for the periods indicated. In connection with the consummation of our initial public offering (IPO), BPHC contributed all of the equity interests in Boardwalk Pipelines to us. This contribution was accounted for as a transfer of assets between entities under common control. Therefore, the results of Boardwalk Pipelines prior to November 15, 2005, have been combined with our results subsequent to November 15, 2005, as our consolidated results for 2005.

Prior to its converting to a limited partnership on November 15, 2005, Boardwalk Pipelines' taxable income was included in the consolidated federal income tax return of Loews and Boardwalk Pipelines recorded a charge-in-lieu of income taxes pursuant to a tax-sharing agreement with Loews. The tax-sharing agreement required Boardwalk Pipelines to remit to Loews on a quarterly basis any federal income taxes as if it were filing a separate return. Boardwalk Pipelines and its subsidiaries were also included in the state franchise tax filings of BPHC. The franchise taxes were charged to, and recorded by, Boardwalk Pipelines and its subsidiaries pursuant to the companies' tax sharing policy. Following our IPO, we no longer record certain state franchise taxes incurred by BPHC and no longer participate in a tax-sharing agreement with Loews. Our subsidiaries directly incur some income-based state taxes, which are shown as *Income taxes* on the Consolidated Statements of Income.

As used herein, EBITDA means earnings before interest, income taxes, and depreciation and amortization. This measure is not calculated or presented in accordance with accounting principles generally accepted in the U.S. (GAAP). We explain this measure below and reconcile it to its most directly comparable financial measures calculated and presented in accordance with GAAP in (5) *Non-GAAP Financial Measure* 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 subordinated unit, Net income per class B unit, Distributions per common unit and Distributions per Class B unit):

	Boardwalk Pipeline Partners, LP				
	For the Year Ended December 31,				
	2009	2008	2007	2006	2005
Total operating revenues	**$ 909.2**	$ 784.8	$ 643.2	$ 607.6	$ 560.5
Net income	**162.7**	294.0	227.7	197.6	100.9
Total assets	**6,895.8**	6,721.6	4,122.0	2,909.2	2,437.9
Long-term debt	**3,100.0**	2,889.4	1,847.9	1,350.9	1,101.3
Net income per common unit (1)	**0.88**	2.09	1.91	1.90	(2)
Net income per subordinated unit (1)	**-**	1.68	1.86	1.88	(2)
Net income per class B unit (1)	**0.08**	0.60	-	-	-
Distributions per common unit (3)	**1.95**	1.87	1.74	1.32 (4)	-
Distributions per class B unit	**1.20**	0.30	-	-	-
EBITDA (5)	**498.0**	474.6	349.8	331.5	289.0

(1) In the first quarter 2009, we changed the method used in computing our net income per unit due to changes in GAAP. Net income per unit has been retrospectively adjusted for all prior periods presented. Note 11 in Item 8 contains further information.

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 our 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 our various ownership interests are determined in relation to actual declared distributions and are not based on the assumed allocations required under GAAP.

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. In November 2008, all of the 33.1 million subordinated units converted to common units.

(2) Our net income was $36.0 million, or $0.35 per common and subordinated unit, for the period from November 15, 2005, the closing date of our initial public offering, through December 31, 2005.

(3) Distributions per subordinated unit were the same as the distributions per common unit for the years ended December 31, 2005 through 2008.

(4) The first quarter 2006 distribution 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.

(5) Non-GAAP Financial Measure

We use non-GAAP measures to evaluate our business and performance, including EBITDA. 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.

EBITDA should not be considered an alternative 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 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. However, viewing EBITDA as an indicator 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 is not necessarily comparable to similarly titled measures of another company.

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

	Boardwalk Pipeline Partners, LP				
	For the Year Ended December 31,				
	2009	2008	2007	2006	2005
Net income	**$ 162.7**	$ 294.0	$ 227.7	$ 197.6	$ 100.9
Income taxes and charge-in-lieu of income taxes	**0.3**	1.0	0.8	0.2	49.5
Elimination of cumulative deferred taxes	**-**	-	-	-	10.1
Depreciation and amortization	**203.1**	124.8	81.8	75.8	72.1
Interest expense	**132.1**	57.7	61.0	62.1	60.1
Interest income	**(0.2)**	(2.9)	(21.5)	(4.2)	(3.7)
EBITDA	**$ 498.0**	$ 474.6	$ 349.8	$ 331.5	$ 289.0

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

The following discussion and analysis of financial condition and results of operations should be read in conjunction with our Consolidated Financial Statements and the related Notes thereto, included in Item 8, and with Item 1A, Risk Factors.

Overview

Through our operating subsidiaries, Gulf Crossing, Gulf South and 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 including 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 pipeline, directly serving customers in twelve states and indirectly serving customers throughout the northeastern and southeastern U.S. through numerous interconnections with unaffiliated pipelines. In 2009, our pipeline systems transported approximately 2.1 Tcf of gas resulting in average daily throughput of approximately 5.7 Bcf. Our natural gas storage facilities are comprised of eleven underground storage fields located in four states with aggregate working gas capacity of approximately 163.0 Bcf. We conduct all of our natural gas transportation and integrated storage operations through our operating subsidiaries operating as one segment.

Our transportation services consist of firm transportation, whereby the customer pays a capacity reservation charge to reserve pipeline capacity at certain receipt and delivery points along our pipeline systems, plus a commodity and fuel charge on the volume of natural gas actually transported, and interruptible transportation, whereby the customer pays to transport gas only when capacity is available and used. We offer firm storage services in which the customer reserves and pays for a specific amount of storage capacity, including injection and withdrawal rights, and interruptible storage and PAL services where the customer receives and pays for capacity only when it is available and used. Some PAL agreements are paid for at inception of the service and revenues for these agreements are recognized as service is provided over the term of the agreement. For the year ended December 31, 2009, the percentage of our total operating revenues associated with firm contracts was approximately 89%.

We are not in the business of buying and selling natural gas other than for system management purposes, but changes in the price of natural gas can affect the overall supply and demand of natural gas, which in turn can affect our results of operations. Our business is affected by trends involving natural gas price levels and natural gas price spreads, including spreads between physical locations on our pipeline system, which affect our transportation revenues, and spreads in natural gas prices across time (for example summer to winter), which primarily affect our storage and PAL revenues.

Factors that Impact our Results of Operations

A significant portion of our operating revenues is derived from reservation charges under multi-year firm contracts. For the year ended December 31, 2009, 74% of our operating revenues were associated with reservation charges under firm contracts which do not vary based on capacity utilization. As of December 31, 2009, the weighted average contract life of our contracts was approximately 5.9 years. Our business can be impacted by shifts in supply and demand dynamics, the mix of services requested by customers and by competition and regulatory requirements, particularly when accompanied by downturns or sluggishness in the economy, especially over a longer term.

Competition and Contract Renewals

We compete with numerous interstate and intrastate pipelines throughout our service territory to provide transportation and storage services for our customers. Competition is particularly strong in the Midwest and Gulf Coast states where we compete with numerous existing pipelines, including the Rockies Express Pipeline that transports natural gas from northern Colorado to eastern Ohio and the Mid-Continent Express Pipeline that transports gas from Oklahoma and Texas to Alabama. We will also directly compete with several new pipeline projects that are proposed or under development, including projects originating in the Haynesville Shale area – more specifically, the Tiger Pipeline that will transport gas to Perryville, Louisiana and the Haynesville Extension Pipeline that will transport gas to the industrial complex in southeastern Louisiana - and the Fayetteville Express Pipeline which will originate in the Fayetteville Shale area and continue eastward to Mississippi. For new growth and expansion projects, we compete with other pipelines for contracts mainly with producers that would support such projects in order to transport their gas to market areas. We also compete for renewals of expiring transportation and storage contracts.

Despite these competitive conditions, assuming that customers use all of their reserved capacity, substantially all of our operating capacity is contracted for under long-term firm agreements having a weighted average remaining life of approximately 5.9 years. In 2010, firm contracts representing approximately $101.1 million of annual reservation charges are due to expire, of which approximately $55.1 million has been recontracted as of the filing date of this Form 10-K. In 2009, we were successful in renewing and remarketing firm contracts representing approximately $112.8 million of annual reservation charges that were due to expire during that year, in many cases obtaining favorable rates and extended contract terms. Our ability to remarket available capacity will be impacted by competition from other pipelines, natural gas price volatility, the price differential between locations on our pipeline systems, the economic slowdown and numerous other factors beyond our control. Item 1A, *Risk Factors* contains more information regarding the risks related to competition in our industry.

Natural Gas Prices

Many of our producer customers have been negatively impacted by recent declines in natural gas prices which although remaining elevated from historical levels, have decreased substantially from the peak levels reached during the summer of 2008. This decline in prices has caused several of our producer customers to announce plans to decrease drilling levels and, in some cases, to consider shutting in natural gas production from some producing wells, which could adversely affect the volumes of natural gas we transport. 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 2009 approximately 26% of our revenues were derived from charges based on actual volumes transported. Lower volumes of natural gas transported would result in lower revenues from natural gas transportation operations. Based on the significant level of revenue we receive from reservation capacity charges under long-term contracts and our review of the recent announcements of drilling plans by our customers, we do not expect the current level of natural gas prices to have a significant adverse effect on our operating results. However, we cannot give assurances that this will be the case, or that commodity prices will not decline further, which could result in a further reduction in drilling activities by our producer customers.

In addition, spreads in natural gas prices between time periods, such as winter to summer, impact our PAL and interruptible storage revenues. These period to period price spreads were favorable in 2009 resulting in an increase in PAL and interruptible storage revenues as compared with the 2008 and 2007 periods. We cannot predict future time period spreads or basis differentials.

FERC 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 cost of providing the service, the volumes of gas being transported, how costs are allocated 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. FERC recently initiated such a challenge on three non-affiliated pipelines. 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

Expansion and Growth 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 system. We recently added approximately 1,000 miles of pipeline to our existing systems by completing the following projects: the East Texas Pipeline, the Southeast Expansion, the Gulf Crossing Project and the Fayetteville and Greenville Laterals.

Remediation of Pipe Anomalies

For our East Texas Pipeline, Southeast Expansion, Gulf Crossing Pipeline and the Fayetteville Lateral, we have entered into firm transportation contracts with shippers which would utilize the maximum capacity available from operating at higher than normal operating pressures (up to 0.80 of the pipe's SMYS, which increases the peak-day transmission capacity of the pipeline as opposed to the normal operating pressure of up to 0.72 SMYS). PHMSA retains discretion as to whether to grant, or to maintain, the authority to operate a pipeline at higher than normal operating pressures. Absent the receipt and maintenance of authority from PHMSA to operate at higher than normal operating pressures, we would not be able to transport all of the contracted quantities of natural gas on these pipelines.

While completing the requirements to operate our East Texas Pipeline, Southeast Expansion, Gulf Crossing Pipeline and the Fayetteville Lateral at higher than normal operating pressures, we discovered anomalies in certain pipeline segments on each of the projects. Accordingly, we reduced the operating pressures on each pipeline below normal operating pressures as we performed additional testing procedures, remediated the anomalies and continued to seek authority from PHMSA to increase operating pressures, first to normal operating pressures and subsequently to higher than normal operating pressures under the special permits. We also shut down pipeline segments for periods of time to remediate anomalies.

The pressure reductions and shutdowns that were undertaken to remediate anomalies on our expansion pipeline projects reduced throughput and adversely impacted our transportation revenues, net income and cash flows during 2009. At the same time, our operating costs and expenses, particularly depreciation and property taxes, increased in 2009 due to costs associated with the expansion project pipelines being placed into service. See *Results of Operations* for more information on the impacts of the pipeline pressure reductions and shutdowns on our income.

In December 2009, we received authority from PHMSA to operate our East Texas Pipeline, Southeast Expansion and Gulf Crossing Project (42-inch pipeline expansion projects) under special permits that would allow each of these pipelines to operate at higher than normal operating pressures. We continue to work with PHMSA to obtain the authority to operate our Fayetteville Lateral at the higher than normal operating pressures. Unless we obtain PHMSA's consent to increase operating pressures for the Fayetteville Lateral to higher than normal levels under the special permit, our transportation revenues would not grow to the extent we had originally expected, beginning in mid-2011, as the volume commitments on the Fayetteville Lateral under our existing firm contracts increase. Absent authority to operate the Fayetteville Lateral at higher than normal operating pressures, we could also incur additional costs for system upgrades on that project to increase capacity to meet contracted volume commitments.

See Item 1A, Risk Factors – *We need to obtain and maintain authority from PHMSA to operate at higher than normal operating pressures* for related information.

Expansion and Growth Project Status

Set forth below is information with respect to the status of each of our expansion and growth projects.

East Texas Pipeline. Portions of this pipeline were shut down for periods of time in May and July 2009, during which time we completed the requisite anomaly remediation. In December 2009, we received authority from PHMSA to operate the East Texas pipeline at higher than normal operating pressures, which provides a peak-day transmission capacity of 1.4 Bcf per day. Upon the completion of our Haynesville Project described below, the peak-day transmission capacity of this pipeline is expected to be 2.0 Bcf per day.

Southeast Expansion. Portions of this pipeline were shut down for periods of time in May and July 2009, during which time we completed the requisite anomaly remediation. In December 2009, we received authority from PHMSA to operate the Southeast Expansion pipeline at higher than normal operating pressures, which provides a designated peak-day transmission capacity of 1.9 Bcf per day.

Gulf Crossing Project. The Gulf Crossing Project was shut down the entire month of June 2009, during which time we completed the requisite anomaly remediation. In December 2009, we received authority from PHMSA to operate the Gulf Crossing Project pipeline at higher than normal operating pressures, which provides a peak-day transmission capacity of 1.4 Bcf per day. We expect to increase the peak-day transmission capacity of this pipeline to approximately 1.7 Bcf per day, by adding compression in the first quarter 2010, which has been approved by the FERC.

Fayetteville and Greenville Laterals. During the third quarter 2009, the initial testing of the Fayetteville and Greenville Laterals was completed and it was determined that approximately 1% of the pipeline joints contained anomalies. In September and October 2009, portions of the Fayetteville and Greenville Laterals were shut down in order to remediate anomalies. Effective October 8, 2009, we received authority from PHMSA to operate the Fayetteville and Greenville Laterals at normal operating pressures, which has enabled us to meet our current contractual obligations of approximately 0.8 Bcf per day for the Fayetteville Lateral and 0.4 Bcf per day for the Greenville Lateral. We continue to seek authority to operate our Fayetteville Lateral at the higher than normal operating pressures. Until we have obtained PHMSA's consent to increase operating pressures to higher than normal levels under the special permit, we will not be able to operate that pipeline at its anticipated peak-day transmission capacity as contracted volumes increase in the future. Our Greenville Lateral was constructed to operate at normal operating pressures and we are not seeking the authority to operate that pipeline at higher than normal operating pressures under a special permit.

In January 2010, we added compression facilities that increased peak-day delivery capacity to approximately 1.0 Bcf per day on the Greenville Lateral and approximately 1.1 Bcf per day on the Fayetteville Lateral. The designed peak-day delivery capacity of the Fayetteville Lateral is approximately 1.3 Bcf per day once the authority to operate our Fayetteville Lateral at higher than normal operating pressures is received from PHMSA or we complete other system upgrades on that project. The increase in capacity to 1.3 Bcf per day will be needed to meet contractual commitments that will be in effect in mid-2011.

Haynesville Project. The Haynesville Project consists of adding compression to our East Texas Pipeline in Louisiana, which will add approximately 0.6 Bcf per day of peak-day transmission capacity with delivery capabilities from the DeSoto, Louisiana, area to the Perryville, Louisiana, area. We recently received FERC approval for this expansion, which we anticipate will be in service in late 2010. Customers have contracted for substantially all of the capacity on this project at a weighted-average contract life of approximately 12.2 years.

Clarence Compression Project. The Clarence Compression Project, which also targets production from the Haynesville Shale, will add approximately 0.1 Bcf per day of peak-day transmission capacity. This project will receive gas from the Holly Field area in Northwest Louisiana, and deliver to a point near Olla, Louisiana. Customers have contracted for approximately 0.1 Bcf per day of capacity with a weighted-average contract life of approximately 11.0 years. The compression is expected to be in service in late 2011, subject to FERC approval.

Western Kentucky Storage Expansion Project. We have completed Phase III of our Western Kentucky Storage Expansion project, which consisted of developing approximately 8.3 Bcf of new storage working gas capacity. Customers have contracted for all of the available capacity. Approximately 5.4 Bcf of capacity was placed into service in 2008 and we placed the remaining capacity into service in October 2009. The total capital cost of this project was approximately $69.0 million.

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 2009, 2008 and 2007.

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 expansion projects. The increase in expenses more than offset the increase in revenues from our expansion projects, which were approximately $122.0 million lower than expected due to operating our expansion pipelines at reduced operating pressures and portions of the expansion pipelines being shut down for periods of time during 2009, as discussed under *Expansion and Growth Projects*. 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 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 expansion. Operations 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. Operations 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, $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.

2008 Compared with 2007

Our net income for the year ended December 31, 2008 increased $66.3 million, or 29%, to $294.0 million compared to $227.7 million for the year ended December 31, 2007. The primary drivers for the increase were higher revenues from services associated with our expansion projects and gains from the disposition of coal reserves, gas sales associated with our storage expansion and the settlement of a contract claim. The favorable drivers were partly offset by lower PAL revenues due to unfavorable natural gas price spreads and higher depreciation and property tax expense due to an increase in our asset base from expansion. The 2007 period was unfavorably impacted by a $14.7 million impairment charge related to the Magnolia storage facility.

Operating revenues for the year ended December 31, 2008 increased $141.6 million, or 22%, to $784.8 million, compared to $643.2 million for the year ended December 31, 2007. Gas transportation revenues, excluding fuel, increased $112.1 million, primarily from our expansion projects and higher no-notice and interruptible services on our existing assets. Fuel revenues increased $43.9 million due to expansion-related throughput and higher natural gas prices. Gas storage revenues increased $12.1 million related to an increase in storage capacity associated with our Western Kentucky Storage Expansion. These increases were partially offset by lower PAL revenues of $26.5 million due to unfavorable natural gas price spreads.

Operating costs and expenses for the year ended December 31, 2008 increased $61.0 million, or 16%, to $438.2 million, compared to $377.2 million for the year ended December 31, 2007. The primary drivers were increased depreciation and other taxes, comprised primarily of property taxes, of $56.3 million associated with an increase in our asset base, increased fuel costs of $50.2 million mainly from providing service on our expansion projects and higher natural gas prices and $5.8 million of third party transportation costs associated with providing customers of our expansion projects access to off-system markets. Administrative and general expenses increased $5.4 million due to increased outside services mainly due to legal matters, information technology-related expenses from infrastructure improvements, corporate services, higher property insurance from an increase in rates and asset base and a bad debt recovery that favorably impacted the 2007 period. The increases to operating expenses were offset by gains of $16.5 million from the disposition of coal reserves, $12.4 million on the sale of gas related to our Western Kentucky Storage Expansion and $11.2 million from the settlement of a contract claim. Additionally, in the fourth quarter 2008, we changed our employee paid time off benefits, resulting in a reduction in operation and maintenance expenses of $4.9 million and a reduction of administrative and general expenses of $2.3 million. The 2007 period was unfavorably impacted by a $14.7 million impairment charge related to our Magnolia storage project.

Total other deductions increased by $14.1 million, or 38%, to $51.6 million for the year ended December 31, 2008, compared to $37.5 million for the 2007 period, primarily as a result of $18.6 million of decreased interest income due to lower average cash balances available for investment, partly offset by a $3.3 million reduction in interest expense from higher capitalized interest associated with our expansion projects.

Liquidity and Capital Resources

We are a partnership holding company and derive all of our operating cash flow from our operating subsidiaries. Our principal sources of liquidity include cash generated from operating activities, our revolving credit facility, debt issuances and sales of limited partner units. Our operating subsidiaries use funds from their respective operations to fund their operating activities and maintenance capital expenditures, 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 its revolving credit facility discussed below, to service its outstanding indebtedness and, when available, make distributions or advances to us to fund our distributions to unitholders. We have no guarantees of debt or other similar commitments to unaffiliated parties.

Our 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.

In the past two years, the capital markets have been impacted by global liquidity, credit and recessionary concerns. During this period, we have continued to have access to our credit facility to fund our short-term liquidity needs. In addition, we have issued common units and class B units, received additional contributions from our general partner and received net proceeds from the issuance of long-term debt. See discussion below under *Equity and Debt Financing*. Our ability to continue 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, ability to obtain financing and cash flow generated from future operations will enable us to maintain our current level of operations and our planned operations, including our capital expenditures.

Maintenance Capital Expenditures

Maintenance capital expenditures were $58.9 million, $50.5 million and $47.1 million in 2009, 2008 and 2007. We expect to fund our 2010 maintenance capital expenditures of approximately $70.0 million from our operating cash flows.

Expansion and Growth Capital Expenditures

The following table presents our estimate of total capital expenditures and the amounts invested through December 31, 2009, for our remaining pipeline expansion projects, including expenditures for pipe remediation and our growth projects (in millions):

	Estimated Total Capital Expenditures (1)	Cash Invested through December 31, 2009
Southeast Expansion	$ 755	**$ 753.9**
Gulf Crossing Project	1,765	**1,648.5**
Fayetteville and Greenville Laterals	1,215	**1,000.3**
Pipe Remediation (2)	130	**82.0**
Haynesville Project	185	**15.6**
Clarence Compression	30	**-**
Total	$ 4,080	**$ 3,500.3**

(1) Our estimated total capital expenditures are based on internally developed financial models and timelines. Factors in the estimates include, but are not limited to, those related to pipeline costs based on mileage, size and type of pipe, materials and construction and engineering costs.
(2) This estimate represents the cost of remediating pipe anomalies on our East Texas Pipeline, our Southeast Expansion, our Gulf Crossing Project and our Fayetteville and Greenville Laterals.

In our efforts to obtain the authority from PHMSA to operate our East Texas Pipeline, Southeast Expansion, Gulf Crossing Project and Fayetteville Lateral at higher than normal operating pressures, we have incurred costs to remediate pipeline anomalies as described under *Expansion and Growth Capital Expenditures*. We continue to seek authority to operate our Fayetteville Lateral at higher than normal operating pressures and may incur additional costs to inspect, test and remediate pipe segments on the Fayetteville Lateral in order to obtain from PHMSA the authority to increase operating pressures to higher than normal levels under the special permit.

We expect to incur up to $580.0 million in capital expenditures to complete our expansion and growth projects, including pipe remediation efforts for the Fayetteville Lateral, for which the majority of expenditures are expected to occur by the end of 2010. As discussed in *Remediation of Pipe Anomalies*, absent authority to operate the Fayetteville Lateral at higher than normal operating pressures, we could incur additional costs for other system upgrades on that project to increase capacity to meet contracted volume commitments. Including costs associated with remediating the pipe anomalies and additional cost that we could incur on our Fayetteville Lateral, we expect the total cost to complete our expansion projects to be within our previously announced cost estimates. Our cost and timing estimates for these projects are subject to a variety of risks and uncertainties as discussed in Item 1A, *Risk Factors* of this Report.

Equity and Debt Financing

We have financed our expansion capital expenditures through the issuance of equity and debt, borrowings under our revolving credit facility and available operating cash flows in excess of our operating needs. We do not anticipate the need to raise further capital in order to complete our expansion and growth projects.

In 2009, we received net cash proceeds of approximately $879.8 million from the following equity and debt issuances which proceeds were used to directly and indirectly fund our expansion projects through the reduction of borrowings under our revolving credit facility and, in the case of the debt securities, to reduce borrowings under our Subordinated Loan Agreement by $100.0 million (in millions, except issue price):

Month of Issuance	Net Cash Proceeds Received	Number of Units	Issue Price	Type of Issuance
August	$ 183.1 (1)	8.1	$ 23.00	Public offering of common units
August	346.7	N/A	N/A	Public offering of debt securities
June	150.0 (2)	6.7	21.99	Private placement of common units to BPHC
May	200.0	N/A	N/A	Subordinated loan with BPHC

(1) Includes a $3.8 million contribution received from our general partner to maintain its 2% general partner interest.
(2) Includes a $3.0 million contribution received from our general partner to maintain its 2% general partner interest.

Note 7 in Item 8 of this Report contains more information regarding each of these offerings.

We have also borrowed under our revolving credit facility to finance our expansion projects. As of December 31, 2009, approximately $878.5 million of our long-term debt, including $553.5 million borrowed under our revolving credit facility, matures in 2012. The term of the revolving credit facility may be extended to 2013 as described under *Revolving Credit Facility*. We expect to refinance the debt through the issuance and sale of new debt.

Revolving Credit Facility

We maintain a revolving credit facility which has aggregate lending commitments of $1.0 billion, under which Boardwalk Pipelines, Gulf South and Texas Gas each may borrow funds, up to applicable sub-limits. A financial institution which has a $50.0 million commitment under the revolving credit facility filed for bankruptcy protection in the third quarter 2008 and has not funded its portion of our borrowing requests since that time. 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, 2009, we had $553.5 million of loans outstanding under the revolving credit facility with a weighted-average interest rate on the borrowings of 0.48% and had no letters of credit issued. Subsequent to December 31, 2009, we borrowed an additional $75.0 million, which increased borrowings to $628.5 million. We and our subsidiaries were in compliance with all covenant requirements under our credit facility at December 31, 2009. Note 7 in Item 8 of this Report contains more information regarding our revolving credit facility.

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. 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*. In particular, maintaining compliance with the financial covenant may limit our ability to incur additional indebtedness to finance our growth projects, which could limit our growth opportunities or require the issuance of more equity securities by us than previously anticipated.

Contractual Obligations

The following table summarizes significant contractual cash payment obligations under firm commitments as of December 31, 2009, by period (in millions):

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Principal payments on long-term debt (1)	$ 3,113.5	$ -	$ 878.5	$ 250.0	$ 1,985.0
Interest on long-term debt (2)	1,031.1	147.0	291.2	228.0	364.9
Capital commitments (3)	47.8	47.7	0.1	-	-
Pipeline capacity agreements (4)	79.8	12.4	20.6	20.6	26.2
Operating lease commitments	24.0	4.1	6.5	5.9	7.5
Total	$ 4,296.2	$ 211.2	$ 1,196.9	$ 504.5	$ 2,383.6

(1) This includes our senior unsecured notes, having maturity dates from 2012 to 2027, $553.5 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.

(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 0.48% weighted-average interest rate on amounts outstanding under our revolving credit facility as of December 31, 2009, $2.7 million and $4.0 million would be due under the credit facility in less than one year and 1-3 years.

(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, 2009. The amounts shown do not reflect commitments we have made after December 31, 2009. For information on these projects, see *Expansion and Growth Capital Expenditures*.

(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 2010, we expect to fund approximately $6.0 million to the Texas Gas pension plan.

Distributions

For the twelve months ended December 31, 2009 and 2008, we paid distributions of $360.6 million and $260.5 million to our various ownership interests. Note 11 in Item 8 of this Report contains further discussion regarding our distributions.

Changes in cash flow from operating activities

Net cash provided by operating activities increased $50.2 million to $400.5 million for the year ended December 31, 2009, compared to $350.3 million for the comparable 2008 period, primarily from prepayments received under PAL arrangements in the 2009 period and the settlement of derivatives in the 2008 period.

Changes in cash flow from investing activities

Net cash used in investing activities decreased $2,085.6 million to $671.8 million for the year ended December 31, 2009, compared to $2,757.4 million for the comparable 2008 period, primarily due to a $1,805.7 million decrease in capital expenditures mainly related to our expansion projects and the sale of $175.0 million of short-term investments.

Changes in cash flow from financing activities

Net cash provided by financing activities decreased $2,048.1 million to $179.4 million for the year ended December 31, 2009, compared to $2,227.5 million for the comparable 2008 period. These decreases resulted from a $1,115.7 million reduction in proceeds from the issuance and sale of equity, including related general partner contributions, an $831.0 million decrease in proceeds from the issuance of debt and net borrowings under our revolving credit facility and a $100.1 million increase in distributions to our partners.

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, 2009, 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, 2009 and 2008, 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 record certain costs and benefits as regulatory assets and liabilities, respectively, in order to provide for recovery from or refund to customers in future periods, but is not applicable to operations associated with the Texas Gas Fayetteville and Greenville Laterals project due to rates charged under negotiated rate agreements and Phase III of the Western Kentucky Storage Expansion project due to the regulatory treatment and contractual rates associated with that project. 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 through the receipt or delivery of gas in the future or with cash. 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 approximately $51.2 million of the benefits plan trust assets were based on unobservable data inputs. The fair value measurement associated with our annual 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, 2009, the fair value of our derivatives was determined based on quoted market prices for similar contracts. Notes 2, 8 and 13 to our Consolidated Financial Statements, included 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, 2009, we had accrued approximately $14.1 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.

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.

While we were developing a salt dome storage cavern near Napoleonville, Louisiana, integrity tests completed in 2007 indicated that due to geological and other anomalies that could not be corrected, we would be unable to place the cavern in service as expected. We elected to abandon that cavern and began exploring the possibility of securing a new site on which a new cavern could be developed. The carrying value of the cavern and related facilities was tested for recoverability, and in 2007 we recognized an impairment charge of approximately $14.7 million, representing the carrying value of the cavern, the fair value of which was determined to be zero based on discounted expected future cash flows. We expect to use the other assets associated with the project, which includes pipeline, compressors, and other equipment and facilities, in conjunction with a replacement storage cavern to be developed. If we determine in the future that the assets cannot be used in conjunction with a new cavern or a new cavern cannot be secured in the same area, we may be required to record an additional impairment charge at the time that determination is made.

Goodwill

As of December 31, 2009, 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 Texas Gas. 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. We perform this test annually at December 31.

Beginning in 2009, we were required to determine the reporting unit's fair value in accordance with accounting requirements involving fair value measurements as described under *Fair Value Measurements*. The fair value measurement was derived based on 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 include the valuation premise; the use of a discounted cash flow model to estimate fair value; and the inputs to the valuation model, including 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 in excess of the carrying amount at December 31, 2009, 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.

Further information on our pension and postretirement benefit obligations is included in Note 9 in Item 8 of this Report.

Recent Accounting Pronouncements

For a discussion regarding recently issued accounting pronouncements or accounting pronouncements adopted in 2009, see Notes 2 and 11 in Item 8 of this Report.

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 its 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:

- our ability to operate our East Texas Pipeline, Southeast Expansion, Gulf Crossing Pipeline and Fayetteville Lateral at higher than normal operating pressures;
- the timing, cost, scope and financial performance of our recent and future expansion and growth projects;
- our ability to maintain or replace expiring gas transportation and storage contracts at favorable rates;
- 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;
- the impact of laws and regulations, including changes to laws and regulations, on our business, including our costs, liabilities and revenues;
- operational hazards, litigation and unforeseen interruptions for which we may not have adequate or appropriate insurance coverage;
- the cost of insuring our assets may increase dramatically;
- our ability to access new sources of natural gas and the impact on us of any future decreases in supplies of natural gas in our supply areas;
- the impact of changes in the supply of and demand for natural gas, including as a result of commodity price changes, the impact on our system throughput and revenues;
- the impact of new pipelines or new gas supply sources being located near the markets served by our pipelines on the pricing of our services and our ability to re-contract with customers.

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):

	2009	2008
Carrying value of fixed-rate debt	**$ 2,546.5**	$ 2,097.4
Fair value of fixed-rate debt	**$ 2,615.1**	$ 1,863.3
100 basis point increase in interest rates and resulting debt decrease	**$ 130.7**	$ 117.1
100 basis point decrease in interest rates and resulting debt increase	**$ 140.3**	$ 126.1
Weighted-average interest rate	**5.97%**	5.89%

At December 31, 2009, we had $553.5 million outstanding under our revolving credit agreement at a weighted-average interest rate of 0.48% which rate is reset periodically. A 1% increase in interest rates would increase our cash payments for interest on the credit facility by $5.5 million on an annual basis. At December 31, 2008, we had $792.0 million outstanding under our revolving credit facility at a weighted-average interest rate of 3.43%.

At December 31, 2009 and 2008, $45.8 million and $137.7 million of our undistributed cash, shown on the balance sheets as *Cash and cash equivalents*, was primarily invested in Treasury fund accounts and at December 31, 2008, $175.0 million was invested in U.S. Treasury notes under repurchase agreements and shown as *Short-term investments*. 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:

Certain volumes of our gas stored underground are available for sale and subject to commodity price risk. At December 31, 2009 and 2008, approximately $2.3 million and $0.2 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, 3.3 Bcf of gas with a book value of $7.5 million has become available for sale as a result of Phase III of the Western Kentucky Storage Expansion. We utilize derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas. Our pipelines do not take title to the natural gas which they transport and store in rendering traditional firm and interruptible transportation and storage services, therefore they do not assume the related natural gas commodity price risk associated with that 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 (loss) income*. 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.

Credit risk:

We are exposed to credit risk relating to the risk of loss resulting from the nonperformance by a customer of its contractual obligations. We have established credit policies in the pipeline tariffs which are intended to minimize credit risk in accordance with FERC policies and actively monitor this portion of our business. 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 and cash flows.

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 trillion British thermal units (TBtu). Assuming an average market price during December 2009 of $5.36 per million British thermal unit (MMBtu), the market value of this gas at December 31, 2009, would have been approximately $79.9 million. As of December 31, 2008, the amount of gas loaned out by our subsidiaries or owed to our subsidiaries due to gas imbalances was approximately 34.4 TBtu. Assuming an average market price during December 2008 of $5.85 per MMBtu, the market value of this gas at December 31, 2008, would have been approximately $201.2 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.

Market risk:

Our primary exposure to market risk occurs at the time our existing transportation and storage contracts expire and are subject to termination or renegotiation. In addition, we have market risk exposure if one of our transportation or storage customers defaults on a service agreement and we are unable to resell the capacity at the same or higher rate. As a result of competition in the industry, we actively monitor future expiration dates associated with our contract portfolio. As of December 31, 2009, approximately 14% of the firm contract load on our pipeline systems was due to expire on or before December 31, 2010. As of December 31, 2008, the firm contract load due to expire within one year was 17%. Many of the contracts comprising the 17% were renewed or remarketed at favorable pricing terms and for extended terms.

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, 2009 and 2008, 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, 2009. 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, 2009, 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 16, 2010 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

DELOITTE & TOUCHE LLP
Houston, Texas
February 16, 2010

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED BALANCE SHEETS
(Millions)

ASSETS	December 31, 2009	2008
Current Assets:		
Cash and cash equivalents	**$ 45.8**	$ 137.7
Short-term investments	**-**	175.0
Receivables:		
Trade, net	**95.5**	67.3
Other	**13.5**	18.0
Gas transportation receivables	**7.9**	13.5
Costs recoverable from customers	**6.0**	5.4
Gas stored underground	**2.1**	0.2
Prepayments	**10.1**	17.3
Other current assets	**10.0**	17.4
Total current assets	**190.9**	451.8
Property, Plant and Equipment:		
Natural gas transmission plant	**6,406.7**	3,871.0
Other natural gas plant	**217.1**	215.2
Construction work in progress	**231.4**	2,196.4
Property, plant and equipment, gross	**6,855.2**	6,282.6
Less—accumulated depreciation and amortization	**577.3**	382.4
Property, plant and equipment, net	**6,277.9**	5,900.2
Other Assets:		
Goodwill	**163.5**	163.5
Gas stored underground	**133.7**	124.8
Costs recoverable from customers	**16.1**	15.4
Other	**113.7**	65.9
Total other assets	**427.0**	369.6
Total Assets	**$ 6,895.8**	$ 6,721.6

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, 2009**	**2008**
Current Liabilities:		
Payables:		
Trade	**$ 58.4**	$ 216.4
Affiliates	**8.6**	1.8
Other	**17.8**	7.4
Gas transportation payables	**5.0**	11.6
Accrued taxes, other	**41.2**	35.2
Accrued interest	**41.8**	40.1
Accrued payroll and employee benefits	**16.4**	16.3
Construction retainage	**21.0**	76.3
Deferred income	**20.9**	1.8
Other current liabilities	**19.8**	27.1
Total current liabilities	**250.9**	434.0
Long–term debt	**3,000.0**	2,889.4
Long–term debt – affiliate	**100.0**	-
Total long-term debt	**3,100.0**	2,889.4
Other Liabilities and Deferred Credits:		
Pension liability	**31.6**	35.7
Asset retirement obligation	**18.0**	18.0
Provision for other asset retirement	**47.0**	45.6
Payable to affiliate	**20.6**	20.6
Other	**63.5**	33.3
Total other liabilities and deferred credits	**180.7**	153.2
Commitments and Contingencies		
Partners' Capital:		
Common units – 169.7 and 154.9 million units issued and outstanding as of December 31, 2009 and 2008	**2,640.5**	2,504.8
Class B units – 22.9 million units issued and outstanding as of December 31, 2009 and 2008	**683.6**	692.8
General partner	**65.5**	62.9
Accumulated other comprehensive loss, net of tax	**(25.4)**	(15.5)
Total partners' capital	**3,364.2**	3,245.0
Total Liabilities and Partners' Capital	**$ 6,895.8**	$ 6,721.6

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,		
	2009	2008	2007
Operating Revenues:			
Gas transportation	**$ 794.9**	$ 698.2	$ 529.7
Parking and lending	**34.9**	16.3	42.8
Gas storage	**57.6**	51.5	39.4
Other	**21.8**	18.8	31.3
Total operating revenues	**909.2**	784.8	643.2
Operating Costs and Expenses:			
Fuel and gas transportation	**61.9**	102.4	46.4
Operation and maintenance	**142.2**	119.9	127.4
Administrative and general	**122.0**	106.0	97.0
Depreciation and amortization	**203.1**	124.8	81.8
Contract settlement gain	**-**	(11.2)	-
Asset impairment	**-**	3.0	19.2
Net loss (gain) on disposal of operating assets and related contracts	**8.2**	(49.2)	(23.8)
Taxes other than income taxes	**77.3**	42.5	29.2
Total operating costs and expenses	**614.7**	438.2	377.2
Operating income	**294.5**	346.6	266.0
Other Deductions (Income):			
Interest expense	**125.3**	57.7	61.0
Interest expense – affiliates, net	**6.8**	-	-
Interest income	**(0.2)**	(2.9)	(21.5)
Miscellaneous other income, net	**(0.4)**	(3.2)	(2.0)
Total other deductions	**131.5**	51.6	37.5
Income before income taxes	**163.0**	295.0	228.5
Income tax expense	**0.3**	1.0	0.8
Net income	**$ 162.7**	$ 294.0	$ 227.7
Net income per Unit:			
Basic and diluted net income per limited partner unit:			
Common units (1)	**$ 0.88**	$ 2.09	$ 1.91
Class B units	**$ 0.08**	$ 0.60	$ -
Subordinated units (1)	**$ -**	$ 1.68	$ 1.86
Cash distribution to common and subordinated unitholders (1)	**$ 1.95**	$ 1.87	$ 1.74
Cash distribution to class B units	**$ 1.20**	$ 0.30	$ -
Weighted-average number of limited partners units outstanding:			
Common units (1)	**161.6**	104.2	82.5
Class B units (2)	**22.9**	22.9	-
Subordinated units (1)	**-**	28.7	33.1

(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,		
	2009	2008	2007
OPERATING ACTIVITIES:			
Net income	**$ 162.7**	$ 294.0	$ 227.7
Adjustments to reconcile to cash provided by operations:			
Depreciation and amortization	**203.1**	124.8	81.8
Amortization of deferred costs	**9.4**	9.0	8.3
Amortization of acquired executory contracts	**-**	(0.2)	(1.1)
Asset impairment	**-**	3.0	19.2
Net loss (gain) on disposal of operating assets and related contracts	**8.2**	(49.2)	(23.8)
Changes in operating assets and liabilities:			
Trade and other receivables	**(23.4)**	(16.6)	(4.1)
Gas receivables and storage assets	**(5.0)**	26.2	(1.4)
Costs recoverable from customers	**(1.6)**	0.9	3.6
Inventories	**-**	(8.8)	(2.5)
Other assets	**(18.0)**	(30.5)	(13.3)
Trade and other payables	**25.9**	9.5	(15.9)
Other payables, affiliates	**0.7**	-	-
Gas payables	**2.4**	(15.1)	(11.1)
Accrued liabilities	**4.3**	7.0	12.9
Other liabilities	**31.8**	(3.7)	1.4
Net cash provided by operating activities	**400.5**	350.3	281.7
INVESTING ACTIVITIES:			
Capital expenditures	**(846.8)**	(2,652.5)	(1,209.8)
Proceeds from sale of operating assets, net	**-**	63.8	28.7
Proceeds from insurance reimbursements and other recoveries	**-**	4.7	1.7
Advances to affiliates, net	**-**	1.6	(0.9)
Sales (purchases) of short-term investments	**175.0**	(175.0)	-
Net cash used in investing activities	**(671.8)**	(2,757.4)	(1,180.3)
FINANCING ACTIVITIES:			
Proceeds from long-term debt, net of issuance costs	**346.7**	247.2	495.3
Proceeds from borrowings on revolving credit agreement	**411.5**	1,484.0	-
Repayment of borrowings on revolving credit agreement	**(650.0)**	(692.0)	-
Payments on note payable	**(1.3)**	-	-
Proceeds from long-term debt – affiliate	**200.0**	-	-
Repayment of long-term debt – affiliate	**(100.0)**	-	-
Distributions paid	**(360.6)**	(260.5)	(205.0)
Proceeds from sale of common units	**326.3**	733.6	515.9
Proceeds from sale of class B units	**-**	686.0	-
Capital contribution from general partner	**6.8**	29.2	10.7
Net cash provided by financing activities	**179.4**	2,227.5	816.9
Decrease in cash and cash equivalents	**(91.9)**	(179.6)	(81.7)
Cash and cash equivalents at beginning of period	**137.7**	317.3	399.0
Cash and cash equivalents at end of period	**$ 45.8**	$ 137.7	$ 317.3

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 (Loss) Income	Total Partners' Capital
Balance January 1, 2007	$ 941.8	$ -	$ 285.6	$ 22.1	$ 23.0	$ 1,272.5
Add (deduct):						
Net income	157.2	-	63.5	7.0	-	227.7
Distributions paid	(141.0)	-	(57.4)	(6.6)	-	(205.0)
Sale of common units, net of related transaction costs	515.9	-	-	-	-	515.9
Capital contribution from general partner	-	-	-	10.7	-	10.7
Other comprehensive loss, net of tax	-	-	-	-	(18.8)	(18.8)
Balance December 31, 2007	$ 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**

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,		
	2009	2008	2007
Net income	**$ 162.7**	$ 294.0	$ 227.7
Other comprehensive income (loss):			
Gain (loss) on cash flow hedges	**10.5**	(16.7)	(9.8)
Reclassification adjustment transferred to Net income from cash flow hedges	**(16.5)**	24.9	(7.3)
Pension and other postretirement benefits costs	**(3.9)**	(27.9)	(1.7)
Total comprehensive income	**$ 152.8**	$ 274.3	$ 208.9

These 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, 2009, Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews), owns 114.2 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 72% of the Partnership's equity interests, excluding the IDRs, further described in Note 11. The Partnership is traded under the symbol "BWP" on the New York Stock Exchange (NYSE).

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). Subsequent events have been evaluated through February 16, 2010, the issuance date of these financial statements.

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 record 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 project due to rates charged under negotiated rate agreements and Phase III of the Western Kentucky Storage Expansion project due to the regulatory treatment associated with the rates charged under that project. 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, 2009 and 2008.

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.

Short-Term Investments

Short-term investments consist of United States (U.S.) Government securities, primarily Treasury notes, under repurchase agreements. Generally, the Partnership has engaged in overnight repurchase transactions where purchased securities are sold back to the counterparty the following business day. The amount invested under repurchase agreements is stated at fair value. Certain short-term investments, for example those held overnight, result in significant cumulative inflows and outflows of cash. The Partnership reflects these activities on a net basis in the Investing Activities section of the Consolidated Statements of Cash Flows.

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 84.7 trillion British thermal units (TBtu) of gas owned by third parties as of December 31, 2009. Assuming an average market price during December 2009 of $5.36 per million British thermal unit (MMBtu), the market value of gas held on behalf of others was approximately $454.0 million. As of December 31, 2008, the Partnership held for storage or under PAL agreements approximately 63.8 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,		
	2009	2008	2007
Capitalized interest and allowance for borrowed funds used during construction	$ **10.3**	$ 71.1	$ 27.1
Allowance for equity funds used during construction	**0.4**	0.2	3.0

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 12 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. The Partnership had deferred revenues of $21.3 million and $1.8 million at December 31, 2009 and 2008 related to PAL and interruptible storage services and $8.3 million related to a firm transportation agreement that was paid in advance at December 31, 2009. The deferred revenues related to PAL and interruptible storage services will be recognized in 2010 and 2011 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. Transportation revenues recognized from retained fuel for the years ended December 31, 2009, 2008 and 2007 were $77.5 million, $134.9 million and $73.0 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, 2009 and 2008, 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 Compensation

The Partnership provides 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. These awards are classified as a liability, and consequently are remeasured each reporting period until settlement. The related compensation expense is recognized over the period the employee is required to provide service in exchange for the award, usually the vesting period. Based on the terms of outstanding awards, to the extent forfeitures of awards occur during a period due to employee terminations, cumulative compensation expense previously recognized is reversed in the period of forfeiture. Note 9 contains additional information regarding the Partnership's unit-based 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 its derivatives is determined based on quoted market prices for similar contracts. Notes 8 and 13 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. The impairment test for goodwill is performed annually at December 31. Beginning in 2009, the Partnership is required to determine the reporting unit's fair value in accordance with accounting requirements involving fair value measurements as described under *Fair Value Measurements*.

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 include the valuation premise; use of a discounted cash flow model to estimate fair value; and inputs to the valuation model, including the Partnership's 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 in excess of the carrying amount at December 31, 2009, and accordingly no impairment was recognized. Similarly, no impairment of goodwill was recorded during 2008 or 2007.

Note 3: Commitments and Contingencies

Contractual Release

In December 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.

Calpine Energy Services (Calpine) Settlement

In the first quarter 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.

Legal Proceedings

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, including two that were initially filed as class actions. One of the cases initially filed as a class action was settled in 2008.

A lawsuit entitled ***Crystal Aucoin, et al. v. Gulf South Pipeline Company, LP, et al***., No. 28,157 was filed on February 12, 2004, in the 23rd Judicial District Court for the Parish of Assumption, State of Louisiana. The suit was initially filed as a class action. The defendants at the trial were Gulf South, Dow Chemical Company and Dow Hydrocarbon (jointly, Dow) and one of Gulf South's insurers, Oil Insurance Limited (OIL). The plaintiffs voluntarily dismissed their class action allegations on February 2, 2006. Since that time the case has proceeded in the same court as a mass joinder of approximately 1,200 individual claims. The plaintiffs seek damages for alleged inconvenience and emotional distress arising from being forced to drive on a detour around a road closed due to the gas release. A trial was held in August 2008 on damages for a sample group of 23 plaintiffs. In January 2009, the court awarded damages to these plaintiffs of less than $0.1 million in the aggregate. Gulf South and the other defendants have appealed the ruling. Pursuant to an agreement among the defendants, Gulf South is responsible for one half of the judgment, subject to final determination of Gulf South's claim for indemnification from Dow.

On September 29, 2005, OIL filed suit against Dow, No. 29,217, in the 23rd Judicial District Court for the Parish of Assumption, State of Louisiana, ***Oil Insurance Limited v. Dow Chemical Company, et al***. OIL seeks indemnification from Dow Hydrocarbon for amounts of insurance paid to Gulf South. Dow has filed a demand against OIL and a third-party claim against Gulf South. Dow's allegations against Gulf South include contractual violations and liability due to negligence and strict liability. In this case, Dow seeks recovery for property damage, damages arising from the loss of use of certain wells/caverns and damages incurred responding to and remediating the natural gas leak. The specified damages that Dow has asserted against Gulf South total approximately $220.0 million. In addition, Dow is seeking additional unspecified damages. Gulf South has asserted an affirmative claim of approximately $115.0 million against Dow. Trial of this case is scheduled to begin in April 2010.

Litigation is subject to many uncertainties, and it is possible these actions could be decided unfavorably. The Partnership expects that the claims asserted against Gulf South in each of these cases are covered by insurance that was in effect at the time of the incident. However, if some or all of the claims are not covered by insurance then an adverse outcome in this litigation could have a materially adverse effect on the Partnership's financial condition, results of operations and cash flows. For the years ended December 2009, 2008 and 2007 the Partnership received $3.9 million, $4.7 million and $0.3 million in insurance proceeds related to previously incurred litigation and remediation costs, which were recorded as reductions to *Operating Costs and Expenses*.

Contract Compliance Review

In October 2008, FERC issued an order with respect to an interstate natural gas pipeline not affiliated with the Partnership that redefined what types of changes to a contract are within FERC's jurisdiction and will be viewed by FERC as a material deviation, thereby requiring that the contract be filed with and approved by FERC. In the fall 2008, the Partnership initiated a review of its transportation and storage contracts for both Gulf South and Texas Gas in order to verify compliance with the order. Based upon the findings of this review, the Partnership has reported to FERC that certain of its transportation and storage contracts may not be in compliance with the requirements of the order. The Partnership does not expect the outcome of these findings to have a material impact on its financial condition, results of operations and cash flows.

Other Legal Matters

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

Regulatory and Rate Matters

Expansion and Growth Capital Projects

The Partnership has been engaged in several pipeline expansion and growth projects. In the first quarter 2009, the Partnership placed in service the remaining compression assets associated with its Southeast Expansion. The Partnership also placed in service its Gulf Crossing Project and its Fayetteville and Greenville Laterals. In January 2010, the Partnership placed in service additional compression facilities for its Fayetteville and Greenville Laterals. The Partnership is constructing additional compression facilities for its Gulf Crossing Project, which are expected to be placed in service in the first quarter 2010.

The Partnership has completed Phase III of the Western Kentucky Storage Expansion project, which consisted of developing new working gas capacity at its Midland storage facility for which FERC has granted the Partnership market-based rate authority. A portion of the storage capacity went into service in 2008 and the remaining capacity related to this project was placed into service in October 2009.

In 2008, the Partnership completed and placed into service the remaining portions of the East Texas Pipeline and the pipeline and two compressor stations related to the Southeast Expansion project.

The Partnership's expansion and growth capital expenditures were $754.2 million, $2.6 billion and $1.2 billion for the twelve months ended December 31, 2009, 2008 and 2007.

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, 2009 and 2008, the Partnership had an accrued liability of approximately $14.1 million and $16.8 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, 2009 and 2008, approximately $3.0 million and $3.5 million were recorded in *Other current liabilities* and approximately $11.1 million and $13.3 million were recorded in *Other Liabilities and Deferred Credits*. The Partnership considers environmental assessment, remediation costs and costs associated with compliance with environmental standards to be recoverable through base rates as prudent costs incurred in the ordinary course of business. Therefore, no regulatory asset has been recorded to defer these costs. Note 5 contains further discussion of the Partnership's environmental exposure included in the calculation of its asset retirement obligations.

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 is unable to estimate with any certainty at this time any potential liability it may incur related to this notice but does not expect the outcome to have a material effect on its financial condition, results of operations and 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 and cash flows.

In March 2008, the EPA adopted regulations lowering the 8-hour ozone standard relevant to non-attainment areas. Under the regulation, 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. On January 19, 2010, the EPA proposed to lower the 8-hour ozone standard set in March 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 cost necessary to become compliant with this standard.

Beginning in March 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. In December 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. 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 is currently evaluating the impact that the new federal rules and determinations regarding greenhouse gas emissions may have on its financial condition, results of operations and 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, 2009, 2008 and 2007 were approximately $4.8 million, $4.4 million and $5.0 million. The following table summarizes minimum future commitments related to these items at December 31, 2009 (in millions):

2010	**$ 4.1**
2011	**3.4**
2012	**3.1**
2013	**3.1**
2014	**2.8**
Thereafter	**7.5**
Total	**$ 24.0**

Commitments for Construction

The Partnership incurred $846.8 million and $2.7 billion of capital expenditures in 2009 and 2008. 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, 2009. The commitments as of December 31, 2009 were approximately (in millions):

2010	**$ 47.7**
2011	**0.1**
2012	**-**
2013	**-**
2014	**-**
Thereafter	**-**
Total	**$ 47.8**

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 $10.8 million, $6.4 million and $2.3 million related to pipeline capacity agreements for the years ended December 31, 2009, 2008 and 2007. The future commitments related to pipeline capacity agreements as of December 31, 2009 were (in millions):

2010	**$ 12.4**
2011	**10.3**
2012	**10.3**
2013	**10.3**
2014	**10.3**
Thereafter	**26.2**
Total	**$ 79.8**

Note 4: Property, Plant and Equipment

In 2009, the Partnership placed in service its Gulf Crossing Project and Fayetteville and Greenville Laterals and the remaining compression facilities associated with its Southeast Expansion project. Additionally, the Partnership placed into service the remaining portion of Phase III of the Western Kentucky Storage Expansion project. As a result, approximately $2.5 billion was transferred from work in progress to plant. The assets will generally be depreciated over a term of 35 years.

The following table presents the Partnership's PPE as of December 31, 2009 and 2008 (in millions):

Category		**2009 Class Amount**	**Weighted-Average Useful Lives (Years)**		2008 Class Amount	Weighted-Average Useful Lives (Years)
Depreciable plant:						
Transmission	$	**6,040.8**	**37**	$	3,537.2	39
Storage		**275.1**	**45**		248.9	47
Gathering		**91.6**	**19**		91.4	19
General		**93.5**	**16**		88.3	15
Rights of way and other		**34.8**	**28**		36.9	24
Total utility depreciable plant		**6,535.8**	**37**		4,002.7	39
Non-depreciable:						
Construction work in progress		**231.4**			2,196.4	
Storage		**55.4**			61.6	
Land		**15.3**			13.3	
Other		**17.3**			8.6	
Total other		**319.4**			2,279.9	
Total PPE		**6,855.2**			6,282.6	
Less: accumulated depreciation		**577.3**			382.4	
Total PPE, net	$	**6,277.9**		$	5,900.2	

The non-transmission assets have weighted-average useful lives of 35 years as of December 31, 2009 and 2008 and depreciable asset values of $495.0 million and $465.5 million as of December 31, 2009 and 2008. 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, 2009 and 2008 (in millions):

	2009				2008			
		Gross PPE Investment		**Accumulated Depreciation**		Gross PPE Investment		Accumulated Depreciation
Bistineau storage	**$**	**58.0**	**$**	**8.7**	$	57.1	$	6.9
Mobile Bay Pipeline		**11.3**		**1.7**		11.2		1.4
Offshore and other assets		**19.2**		**11.9**		19.0		11.5
Total	**$**	**88.5**	**$**	**22.3**	$	87.3	$	19.8

Asset Impairments

Non-Contiguous Offshore Laterals. 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.

South Timbalier. In 2007, the Partnership entered into an agreement to sell offshore pipeline assets in the South Timbalier Bay area, offshore Louisiana, and recognized an impairment charge of approximately $4.5 million representing the net book value of the assets. In accordance with the agreement, the Partnership paid the buyer approximately $4.8 million primarily to settle a liability to cover the pipeline and other maintenance issues which was recorded to *Operation and maintenance expense*. The Partnership completed the sale of these assets in 2008.

Magnolia Storage Facility. While the Partnership was developing a salt dome storage cavern near Napoleonville, Louisiana, integrity tests completed in 2007 indicated that due to geological and other anomalies that could not be corrected, the Partnership would be unable to place the cavern in service as expected. The Partnership elected to abandon that cavern and began exploring the possibility of securing a new site on which a new cavern could be developed. The carrying value of the cavern and related facilities was tested for recoverability, and in 2007, the Partnership recognized an impairment charge to earnings of approximately $14.7 million, representing the carrying value of the cavern, the fair value of which was determined to be zero based on discounted expected future cash flows. The charge was presented as *Asset impairment* on the Consolidated Statements of Income in 2007. The Partnership is exploring the possibility of securing a new site on which a new cavern could be developed and expects to use the other assets associated with the project, which include pipeline, compressors and other equipment and facilities, in conjunction with the replacement storage cavern to be developed. If it is determined in the future that the assets cannot be used in conjunction with a new cavern or a new cavern cannot be secured in the same area, the Partnership may be required to record an additional impairment charge at the time that determination is made.

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):

	2009	2008
Balance at beginning of year	**$ 18.0**	$ 16.1
Liabilities recorded	**2.1**	1.6
Liabilities settled	**(2.9)**	(0.5)
Accretion expense	**0.8**	0.8
Balance at end of year	**$ 18.0**	$ 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 and 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 $47.0 million and $45.6 million as of December

31, 2009 and 2008, 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, 2009 and 2008, 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, 2009 and 2008 (in millions):

	2009	2008
Regulatory Assets:		
Pension	**$ 10.6**	$ 9.5
Tax effect of AFUDC equity	**5.5**	5.9
Unamortized debt expense and premium on reacquired debt	**8.9**	10.0
Postretirement benefits other than pension	**5.4**	5.4
Fuel tracker	**0.6**	-
Total regulatory assets	**$ 31.0**	$ 30.8
Regulatory Liabilities:		
Cashout and fuel tracker	**$ 1.9**	$ 2.3
Provision for other asset retirement	**47.0**	45.6
Unamortized discount on long-term debt	**(2.9)**	(3.5)
Postretirement benefits other than pension	**17.6**	4.7
Other	**0.5**	-
Total regulatory liabilities	**$ 64.1**	$ 49.1

Note 7: Financing

Long-Term Debt

The following table presents all long-term debt issues outstanding as of December 31, 2009 and 2008 (in millions):

	2009	2008
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**	-
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**	2,110.0
Revolving Credit Facility:		
Boardwalk Pipelines	**135.0**	285.0
Gulf South	**228.5**	317.0
Texas Gas	**190.0**	190.0
Total revolving credit facility	**553.5**	792.0
Subordinated Loan Agreement with BPHC	**100.0**	-
	3,113.5	2,902.0
Less: unamortized debt discount	**(13.5)**	(12.6)
Total Long-Term Debt	**$ 3,100.0**	$ 2,889.4

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

2010	-
2011	-
2012	$ 878.5
2013	250.0
2014	-
Thereafter	1,985.0
Total long-term debt	$ 3,113.5

Notes and Debentures

For the years ended December 31, 2009, 2008 and 2007, the Partnership completed the following debt issuances, the proceeds of which were used to directly and indirectly fund the Partnership's expansion projects through the reduction of borrowings under its Subordinated Loan Agreement and revolving credit facility, both described below (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
August 2007	Gulf South	225.0	2.0	223.0	5.75%	August 15, 2012	February 15 and August 15
August 2007	Gulf South	275.0	2.7	272.3	6.30%	August 15, 2017	February 15 and August 15

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, 2009 and 2008, 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, 2009, Boardwalk Pipelines and the operating subsidiaries were in compliance with their debt covenants.

Long-Term Debt - Affiliate

In the second quarter 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. The Subordinated Loans must be prepaid with the net cash proceeds from the issuance of additional equity securities by the Partnership or the incurrence of certain indebtedness by the Partnership or its subsidiaries 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. During the third quarter 2009, the Partnership repaid $100.0 million outstanding under the Subordinated Loans, including accrued interest. As of December 31, 2009, the Partnership had $100.0 million outstanding under the Subordinated Loan Agreement with no additional borrowing capacity available.

Revolving Credit Facility

The Partnership has a revolving credit facility which has aggregate lending commitments of $1.0 billion. A financial institution which has a $50.0 million commitment under the revolving credit facility filed for bankruptcy protection in 2008 and has not funded its portion of the Partnership's borrowing requests since that time. Borrowings outstanding under the credit facility as of December 31, 2009 and 2008, were $553.5 and $792.0 million with a weighted-average borrowing rate of 0.48% and 3.43%. Subsequent to December 31, 2009, the Partnership borrowed an additional $75.0 million, which increased borrowings to $628.5 million.

The credit facility contains various restrictive covenants and other usual and customary terms and conditions, including limitations on the payment of cash dividends by the Partnership's subsidiaries and other restricted payments, the incurrence of additional debt, the sale of assets, and sales-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, 2009 and 2008. 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.

Issuances of Common Units

For the years ended December 31, 2009, 2008 and 2007, the Partnership completed the following issuances and sales of common units, the proceeds of which were used to finance a portion of the Partnership's expansion activities discussed in Note 3 or to reduce borrowings under the Partnership's revolving credit facility. 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
November 2007	7.4	30.90	3.7	232.8	90.7	37.4
March 2007	8.0	36.50	4.2	293.8	83.2	29.9

(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 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 repay amounts borrowed under its revolving credit facility and to 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, 2007 (in millions):

	Common Units	Class B Units	Subordinated Units
Balance, January 1, 2007	75.2	-	33.1
Common units issued in connection with underwritten offerings	15.4	-	-
Balance, December 31, 2007	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	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 the common units acquired by BPHC in June 2009 and October 2008 and the common units to be acquired upon conversion of the class B Units. The Partnership also agreed to pay the expenses, including accounting and legal expenses, incurred by BPHC in the sale of such securities and to reimburse BPHC for any underwriting discounts and commissions on the sale by BPHC of certain of such common units. In connection with the June 2009 private placement of common units to BPHC, this agreement was amended to increase the number of units for which the Partnership has agreed to reimburse BPHC for underwriting discounts and commissions from 21.2 million to 27.9 million, up to a maximum of $0.914 per common unit. As of December 31, 2009 and 2008, the Partnership had accrued liabilities of approximately $26.7 million and $20.6 million as a result of the contingent obligation to BPHC.

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 $2.3 million and $0.2 million of gas stored underground at December 31, 2009 and 2008, which the Partnership owns and carries on its Consolidated Balance Sheets as current *Gas stored underground*, and 3.3 billion cubic feet (Bcf) of gas with a book value of $7.5 million that has become available for sale as a result of Phase III of the Western Kentucky Storage Expansion. At December 31, 2009, approximately 5.6 Bcf of anticipated future sales of natural gas and cash for fuel reimbursement were hedged with derivatives having settlement dates in 2010. 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, 2009 and 2008, were included in the following captions in the Consolidated Balance Sheets (in millions):

	Asset Derivatives				**Liability Derivatives**			
	December 31,				**December 31,**			
	2009		2008		**2009**		2008	
	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	**$ 6.2**	Other current assets	$ 10.5	Other current liabilities	**$ -**	Other current liabilities	$ 0.1
	Other assets	**-**	Other assets	3.7	Other liabilities	**-**	Other liabilities	-
		$ 6.2		$ 14.2		**$ -**		$ 0.1

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, 2009 and 2008.

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 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 loss was recognized in the year ended December 31, 2009. The Partnership recognized a loss of $1.7 million for the year ended December 31, 2008.

The Partnership estimates that approximately $5.3 million of net gains reported in AOCI as of December 31, 2009, 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, 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	$ 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 which were settled in previous periods and are being amortized to earnings over the terms of related interest payments, generally the terms of the related debt.

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, 2009, 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, 2009, 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, 2009, the Partnership was not required to post any collateral nor did it hold any collateral associated with its outstanding derivatives. At December 31, 2008, the Partnership held $5.4 million in cash collateral related to its outstanding derivatives.

Note 9: Employee Benefits

Defined Benefit Retirement Plans

Texas Gas employees hired before 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. Effective November 1, 2006, the Pension Plan was closed to new participants and new employees are provided benefits under a defined contribution money purchase plan. 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 2009 and 2008, the Partnership funded $6.0 million and $4.6 million to the Pension Plan and expects to fund approximately $6.0 million to the plan in 2010. The Partnership does not anticipate that any Pension Plan assets will be returned to the Partnership during 2010. Through December 31, 2009, no funding has been provided for the SRP other than the payment of benefits under the plan, and 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 its most recent 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 any amounts of 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. The Partnership did not make contributions to the PBOP plan in 2009. The Partnership contributed $0.8 million to the plan in 2008. 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 2010. The Partnership does not anticipate that any plan assets will be returned to the Partnership during 2010. 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, 2009 and 2008, were as follows (in millions):

	Retirement Plans For the Year Ended December 31,		PBOP For the Year Ended December 31,	
	2009	2008	**2009**	2008
Change in benefit obligation:				
Benefit obligation at beginning of period	**$ 109.9**	$ 108.5	**$ 52.4**	$ 56.9
Service cost	**3.7**	3.7	**0.5**	0.6
Interest cost	**7.0**	6.5	**3.0**	3.2
Plan participants' contributions	**-**	-	**1.0**	1.1
Actuarial loss (gain)	**6.5**	(3.4)	**(0.1)**	(6.2)
Benefits paid	**(5.1)**	(4.0)	**(3.6)**	(3.2)
Settlement	**-**	(1.4)	**-**	-
Benefit obligation at end of period	**$ 122.0**	$ 109.9	**$ 53.2**	$ 52.4
Change in plan assets:				
Fair value of plan assets at beginning of period	**$ 74.2**	$ 91.3	**$ 66.7**	$ 84.2
Actual return on plan assets	**15.3**	(16.3)	**8.7**	(16.2)
Benefits paid	**(5.1)**	(4.0)	**(3.6)**	(3.2)
Company contributions	**6.0**	4.6	**-**	0.8
Plan participants' contributions	**-**	-	**1.0**	1.1
Settlement	**-**	(1.4)	**-**	-
Fair value of plan assets at end of period	**$ 90.4**	$ 74.2	**$ 72.8**	$ 66.7
Funded status	**$ (31.6)**	$ (35.7)	**$ 19.6**	$ 14.3
Items not recognized as components of net periodic cost:				
Prior service cost (credit)	**$ 0.1**	$ 0.1	**$ (47.5)**	$ (55.2)
Net actuarial loss	**25.7**	31.0	**18.7**	25.6
Total	**$ 25.8**	$ 31.1	**$ (28.8)**	$ (29.6)

At December 31, 2009 and 2008, the following aggregate information relates only to the underfunded plans (in millions):

	For the Year Ended December 31,	
	2009	2008
Projected benefit obligation	**$ 122.0**	$ 109.9
Accumulated benefit obligation	**109.3**	97.4
Fair value of plan assets	**90.4**	74.2

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, 2009, 2008 and 2007 were as follows (in millions):

	Retirement Plans			PBOP		
	For the Year Ended December 31,			For the Year Ended December 31,		
	2009	2008	2007	**2009**	2008	2007
Service cost	**$ 3.7**	$ 3.7	$ 3.9	**$ 0.5**	$ 0.6	$ 0.6
Interest cost	**7.0**	6.5	6.6	**3.0**	3.2	3.3
Expected return on plan assets	**(5.6)**	(6.8)	(7.1)	**(3.4)**	(5.0)	(4.7)
Amortization of prior service credit	**-**	-	-	**(7.7)**	(7.8)	(7.8)
Amortization of unrecognized net loss	**2.1**	0.1	0.2	**1.5**	0.1	0.7
Settlement charge	**-**	0.3	4.5	**-**	-	-
Regulatory asset (increase) decrease	**(1.1)**	-	(1.7)	**5.4**	5.4	5.4
Net periodic benefit cost	**$ 6.1**	$ 3.8	$ 6.4	**$ (0.7)**	$ (3.5)	$ (2.5)

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 and 2007, 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
2010	$ 5.3	$ 4.2
2011	5.4	4.1
2012	9.2	3.9
2013	10.3	3.8
2014	11.4	3.8
2015-2019	77.6	19.0

Weighted –Average Assumptions

Weighted-average assumptions used to determine benefit obligations for the years ended December 31, 2009 and 2008 were as follows:

	Retirement Plans		PBOP	
	For the Year Ended December 31,		For the Year Ended December 31,	
	2009	2008	**2009**	2008
Discount rate	**5.70%**	6.30%	**5.70%**	6.30%
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,		
	2009	2008	2007	**2009**	2008	2007
Discount rate	**6.30%**	6.00%	5.94%	**6.30%**	6.00%	5.75%
Expected return on plan assets	**7.50%**	7.50%	7.50%	**5.35%to5.35%**	6.15%to6.15%	5.00%to6.15%
Rate of compensation increase	**4.00%**	4.00%	5.50%	**-**	-	-

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, 2009 (in millions):

	2009
Effect of 1% Increase:	
Benefit obligation at end of year	**$ 1.3**
Total of service and interest costs for year	**0.1**
Effect of 1% Decrease:	
Benefit obligation at end of year	**$ (1.5)**
Total of service and interest costs for year	**(0.1)**

For measurement purposes, at 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. For December 31, 2008, health care costs for the plans were assumed to increase 9% for 2009-2010 grading down to 5% in 0.5% annual increments for participants not eligible for Medicare and 9.5% grading down to 5% in 0.5% annual increments for participants eligible for Medicare.

Pension Plan and PBOP Asset Allocation and Investment Strategy

Pension Plan

The Pension Plan investments are held in a trust account and consist of an undivided interest in an investment account of the Loews Corporation Employees Retirement Trust (Master Trust), a 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 plan. The fair value of the interest in the assets of the Master Trust associated with the Pension Plan as of December 31, 2009, was $90.4 million or 48.6%.

The Master Trust assets are valued at fair value. Equity securities are publicly traded securities using quoted market prices and are considered a Level 1 investment. 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. Approximately 94% of the Pension Plan limited partnership investments are reported on a current basis through December 31, 2009, with no reporting lag and approximately 6% are reported on a lag greater than one month.

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
Beginning 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)
Ending Balance - December 31, 2009	$ 35.6

PBOP

The PBOP plan assets are held in a trust and are valued at fair value. Short-term investments that are actively traded or have quoted prices, such as money market funds, are considered a Level 1 investment. 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 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 are reported on a current basis through December 31, 2009, with no reporting lag.

The following table sets forth by level within the fair value hierarchy a summary of the PBOP Trust's 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
Beginning 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	-
Ending Balance - December 31, 2009	$ 15.6

Investment strategy

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, although subsequent to December 31, 2009, the Partnership has notified the PBOP limited partnerships of its intent to redeem its limited partnership interests. 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.

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 $6.6 million, $5.7 million and $5.3 million for the years ended December 31, 2009, 2008 and 2007.

Strategic Long-Term Incentive Plan

In 2006, Boardwalk GP approved the Partnership's Strategic Long-Term Incentive Plan (SLTIP). The SLTIP provides for the issuance of up to 500 phantom general partner units (Phantom GP Units) to selected employees of the Partnership and its subsidiaries. The Partnership believes that such awards better align the interests of the selected employees with those of the general partner and common unitholders. 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, 2009 and 2008 and changes during the years ended December 31, 2009 and 2008, is presented below:

	Phantom GP Units	**Total Fair Value (in millions)**	**Weighted-Average Vesting Period (in years)**
Outstanding at January 1, 2008 (1)	361	$ 18.1	3.0
Granted (2)	125	6.3	4.0
Paid	(33)	(0.4)	-
Forfeited	(76)	-	-
Outstanding at December 31, 2008 (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**

(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 $3.8 million, $1.1 million and $3.3 million in *Administrative and general* expenses during 2009, 2008 and 2007 for the ratable recognition of the GP Phantom Unit awards fair value. The total estimated remaining unrecognized compensation expense related to the GP Phantom Units outstanding at December 31, 2009, of $12.0 million will be recognized over the average remaining vesting period of approximately 2.0 years. Approximately 11 Phantom GP Units were available for grant under the plan at December 31, 2009.

Long-Term Incentive Plan

In 2005, the Partnership adopted the Long-Term Incentive Plan (LTIP) for the officers and directors of its general partner and for selected employees of its subsidiaries. The Partnership believes that such awards better align the interests of the selected employees with those of the common unitholders. The Partnership reserved 3,525,000 units for grants of units, restricted units, unit options and unit appreciation rights under the plan. The Partnership has granted 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 Partnership's LTIP as of December 31, 2009 and 2008 and changes during the years ended December 31, 2009 and 2008, is presented below:

	Phantom Common Units	**Total Fair Value (in millions)**	**Weighted-Average Vesting Period (in years)**
Outstanding at January 1, 2008 (1)	108,521	$ 3.5	1.8
Granted	54,033	1.1	2.5
Paid	(32,907)	(0.8)	-
Forfeited	(21,359)	-	-
Outstanding at December 31, 2008 (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**

(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 is 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, 2009 and 2008, of $30.03 and $17.78 plus the accumulated value of 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 $1.7 million, $0.4 million and $1.1 million in *Administrative and general* expenses during 2009, 2008 and 2007 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, 2009, of $1.3 million will be recognized over the average remaining vesting period of approximately 1.4 years.

In 2009 and 2008, the general partner purchased 1,500 of the Partnership's common units each year in the open market at a price of $20.58 and $23.78 per unit. These units were granted under the LTIP to the independent directors as part of their director compensation. At December 31, 2009, 3,519,500 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: Disposition of 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 on disposal of operating assets and related contracts* in the Consolidated Statements of Income.

Note 11: Net Income per Limited Partner Unit and Cash Distributions

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
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 class B units began sharing in income allocations and distributions with respect to the third quarter 2008.

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	Amount Paid to General Partner (Including IDRs) (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
November 12, 2007	0.450	52.3	-	2.2
August 13, 2007	0.440	51.1	-	1.7
May 14, 2007	0.430	50.1	-	1.5
February 27, 2007	0.415	44.9	-	1.2

(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) In 2009, 2008 and 2007, the Partnership paid $13.3 million, $7.5 million and $2.5 million in distributions on behalf of IDRs.

In February 2010, the Partnership declared a quarterly cash distribution to unitholders of record of $0.50 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, 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 per unit		$ 0.88	$ 0.08	

In the first quarter 2009, the Partnership changed the method used in computing its net income per unit due to changes in GAAP. As a result, net income per unit for the twelve months ended December 31, 2008 and 2007, has been retrospectively adjusted from $1.98 and $1.87 per common and subordinated unit, as originally reported, to $2.09 and $1.91 per common unit and $1.68 and $1.86 per subordinated unit. There was no change to net income per unit for the class B units for the twelve months ended December 31, 2008. 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.

The following table provides a reconciliation of net income and the assumed allocation of net income to the common and subordinated units for purposes of computing net income per unit for the year ended December 31, 2007 (in millions, except per unit data):

	Total	Common Units	Subordinated Units	General Partner And IDRs
Net income	$ 227.7			
Declared distribution	218.5	$ 151.5	$ 58.9	$ 8.1
Assumed allocation of undistributed net income	9.2	6.4	2.6	0.2
Assumed allocation of net income	$ 227.7	$ 157.9	$ 61.5	$ 8.3
Weighted average units outstanding		82.5	33.1	
Net income per unit		$ 1.91	$ 1.86	

Note 12: Income Tax

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 Condensed 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 tax expense* on the Consolidated Statements of Income.

Following is a summary of the provision for income taxes for the periods ended December 31, 2009, 2008 and 2007 (in millions):

	For the Year Ended December 31,		
	2009	2008	2007
Current expense:			
State	**$ 0.2**	$ 0.7	$ 0.8
Total	**0.2**	0.7	0.8
Deferred provision:			
State	**0.1**	0.3	-
Total	**0.1**	0.3	-
Income taxes	**$ 0.3**	$ 1.0	$ 0.8

The Partnership's tax years 2006 through 2008 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, 2009, 2008 and 2007. As of December 31, 2009 and 2008, there were no significant deferred income tax assets or liabilities.

Note 13: 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 and liabilities, the carrying amount is a reasonable estimate of fair value due to the short maturity of those instruments.

Short-term investments: In December 2008, the Partnership invested a portion of its undistributed cash in U.S. Government securities, primarily Treasury notes, under repurchase agreements. Generally, the Partnership has engaged in overnight repurchase transactions where purchased securities are sold back to the counterparty the following business day. Pursuant to the master repurchase agreements, the Partnership takes actual possession of the purchased securities. In the event of default by the counterparty under the agreement, the repurchase would be deemed immediately to occur and the Partnership would be entitled to sell the securities in the open market, or give the counterparty credit based on the market price on such date, and apply the proceeds (or deemed proceeds) to the aggregate unpaid repurchase amounts and any other amounts owed by the counterparty.

At December 31, 2008, the portfolio consisted of $175.0 million of Treasury securities with original maturities in August 2009, held pursuant to overnight repurchase agreements. The amount invested under repurchase agreements was stated at fair value based on quoted market prices for the securities. The Partnership had no short-term investments at December 31, 2009.

Long-Term Debt: All of the Partnership's long-term debt is publicly traded except for debt issued by Gulf South, the debt issued by Texas Gas in March 2008, the revolving credit facility and the Subordinated Loans categorized as *Long-term debt - affiliate*. The estimated fair value of the Partnership's publicly traded debt is based on quoted market prices at December 31, 2009 and 2008. The fair market value of the debt that is not publicly traded is based on market prices of similar debt at December 31, 2009 and 2008.

Long-Term Debt - Affiliate: Borrowings under the Subordinated Loans were completed in 2009. The estimated fair value is based on market prices of similar debt, adjusted for the affiliated nature of the transaction. Note 7 contains more information regarding the Subordinated Loans.

The carrying amount and estimated fair values of the Partnership's financial instruments as of December 31, 2009 and 2008 were as follows (in millions):

	2009		2008	
Financial Assets	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Cash and cash equivalents	**$ 45.8**	**$ 45.8**	$ 137.7	$ 137.7
Short-term investments	**-**	**-**	175.0	175.0
Financial Liabilities				
Long-term debt	**$ 3,000.0**	**$ 3,060.6**	$ 2,889.4	$ 2,655.3
Long-term debt – affiliate	**100.0**	**108.0**	-	-

Note 14: Accumulated Other Comprehensive Income (Loss)

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

	For the Year Ended December 31,	
	2009	2008
Loss on cash flow hedges, net of tax	**$ (6.7)**	$ (0.7)
Deferred components of net periodic benefit cost, net of tax	**(18.7)**	(14.8)
Total Accumulated other comprehensive loss, net of tax	**$ (25.4)**	$ (15.5)

In 2010, the Partnership expects to recognize in earnings approximately $10.7 million of the amounts included in the table. This amount is comprised of increases to earnings of $5.3 million related to cash flow hedges and $5.4 million related to net periodic benefit cost.

Note 15: 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,					
	2009		2008		2007	
Customer	**Revenue**	**%**	Revenue	%	Revenue	%
Devon Energy Production Company, LP	**$ 102.6**	**11%**	$ 47.2	6%	$ 16.8	3%
Atmos Energy	**53.7**	**6%**	73.0	9%	63.9	10%

Gas Loaned to Customers

Natural gas price volatility can cause changes in credit risk related to gas loaned to customers. 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 that gas was approximately $79.9 million. As of December 31, 2008, the amount of gas owed to the operating subsidiaries due to gas imbalances and gas loaned under PAL agreements was approximately 34.4 TBtu. Assuming an average market price during December 2008 of $5.85 per MMBtu, the market value of this gas at December 31, 2008, would have been approximately $201.2 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 and cash flows.

Note 16: Related Party Transactions

Loews provides a variety of corporate services to the Partnership and its subsidiaries under services agreements which have been operative since 2005. Services provided by Loews include, among others, information technology, tax, risk management, internal audit and corporate development services. Loews charged $17.1 million, $14.5 million and $12.1 million for the years ended December 31, 2009, 2008 and 2007 to the Partnership for performing these services, plus related expenses and allocated overhead.

Distributions paid related to limited partner units held by BPHC and the 2% general partner interest and IDRs held by Boardwalk GP were $264.2 million, $181.1 million and $156.4 million for the years ended December 31, 2009, 2008 and 2007.

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. Note 7 contains more information regarding these transactions.

Note 17: Supplemental Disclosure of Cash Flow Information (in millions):

	For the Year Ended December 31,		
	2009	2008	2007
Cash paid during the period for:			
Interest (net of amount capitalized)	**$ 124.4**	$ 42.8	$ 46.1
Income taxes, net	**0.2**	0.8	0.3
Non-cash adjustments:			
Accounts payable and PPE	**$ 173.2**	$ 86.8	$ 175.8
Accrued registration rights costs	**6.1**	20.6	-

Note 18: Selected Quarterly Financial Data (Unaudited)

The following tables summarize selected quarterly financial data for 2009 and 2008 for the Partnership (in millions, except for earnings per unit):

	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 (benefit)	**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**

	2008 For the Quarter Ended:			
	December 31	September 30	June 30	March 31
Operating revenues	$ 205.6	$ 191.6	$ 190.3	$ 197.3
Operating expenses	130.3	102.8	109.3	95.8
Operating income	75.3	88.8	81.0	101.5
Interest expense, net	10.9	8.6	17.3	18.0
Other (income) expense	(3.4)	6.3	(1.2)	(4.9)
Income before income taxes	67.8	73.9	64.9	88.4
Income taxes	0.2	0.3	0.2	0.3
Net income	$ 67.6	$ 73.6	$ 64.7	$ 88.1
Net income per unit:				
Common units	$ 0.46 (1)	$ 0.47	$ 0.50	$ 0.68
Class B units	$ 0.20 (1)	$ 0.30	$ -	$ -
Subordinated units	$ (0.10) (1)	$ 0.47	$ 0.46	$ 0.68
Total Comprehensive Income	$ 55.4	$ 100.3	$ 56.5	$ 62.1

(1) As discussed in Note 11, in the first quarter 2009, the Partnership changed the method used in computing its net income per unit due to a change in GAAP. As a result, the net income per unit for the quarter ended December 31, 2008, has been retrospectively adjusted from $0.40 per common and subordinated unit to $0.46 per common unit and $(0.10) per subordinated unit. Additionally, net income

per unit for the quarter ended December 31, 2008, was retrospectively adjusted from $0.30 per class B unit to $0.20 per class B unit.

Note 19: Guarantee of Securities of Subsidiaries

The Partnership's Boardwalk Pipelines subsidiary (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, 2009 and 2008. Note 7 contains additional information regarding the Partnership's debt and related covenants.

The Partnership has provided the following condensed consolidating financial information which was not previously presented, 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, 2009
(in millions)

Assets	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Cash	$ -	$ 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
Advances from affiliates - noncurrent	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 Balance Sheets as of December 31, 2008
(in millions)

Assets	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Cash	$ -	$ 137.6	$ 0.1	$ -	$ 137.7
Short-term investments	-	175.0	-	-	175.0
Receivables	-	-	190.1	(104.8)	85.3
Gas stored underground	-	-	0.2	-	0.2
Prepayments	-	-	17.3	-	17.3
Advances to affiliates	-	-	223.8	(223.8)	-
Other current assets	0.8	-	36.1	(0.6)	36.3
Total current assets	0.8	312.6	467.6	(329.2)	451.8
Investment in consolidated subsidiaries	1,005.0	4,303.9	-	(5,308.9)	-
Property, plant and equipment, gross	0.6	-	6,282.0	-	6,282.6
Less–accumulated depreciation and amortization	(0.3)	-	(382.1)	-	(382.4)
Property, plant and equipment, net	0.3	-	5,899.9	-	5,900.2
Other noncurrent assets	1.7	2.0	366.7	(0.8)	369.6
Advances to affiliates - noncurrent	2,262.0	154.2	253.2	(2,669.4)	-
Total other assets	2,263.7	156.2	619.9	(2,670.2)	369.6
Total Assets	$ 3,269.8	$ 4,772.7	$ 6,987.4	$ (8,308.3)	$ 6,721.6

Liabilities & Partners' Capital/Member's Equity	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Payables	$ 2.1	$ -	$ 328.3	$ (104.8)	$ 225.6
Advances from affiliates	-	223.8	-	(223.8)	-
Other current liabilities	1.6	12.7	195.5	(1.4)	208.4
Total current liabilities	3.7	236.5	523.8	(330.0)	434.0
Total long-term debt	-	1,015.9	1,873.5	-	2,889.4
Advances from affiliates - noncurrent	20.6	2,515.3	154.1	(2,669.4)	20.6
Other noncurrent liabilities	0.5	-	132.1	-	132.6
Total other liabilities and deferred credits	21.1	2,515.3	286.2	(2,669.4)	153.2
Total partners' capital/member's equity	3,245.0	1,005.0	4,303.9	(5,308.9)	3,245.0
Total Liabilities and Partners' Capital/Member's Equity	$ 3,269.8	$ 4,772.7	$ 6,987.4	$ (8,308.3)	$ 6,721.6

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, affiliate	-	55.9	11.8	(60.9)	6.8
Interest expense	-	49.9	75.4	-	125.3
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)
	(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	-	-	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	-	-	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)
	(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 Income for the Year Ended December 31, 2007
(in millions)

	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Operating revenues:					
Gas transportation	$ -	$ -	$ 538.8	$ (9.1)	$ 529.7
Parking and lending	-	-	42.8	-	42.8
Gas storage	-	-	39.4	-	39.4
Other	-	-	31.3	-	31.3
Total operating revenues	-	-	652.3	(9.1)	643.2
Operating cost and expenses:					
Fuel and gas transportation	-	-	55.5	(9.1)	46.4
Operation and maintenance	-	-	127.4	-	127.4
Administrative and general	(0.2)	-	97.2	-	97.0
Other operating costs and expenses	0.2	-	106.2	-	106.4
Total operating costs and expenses	-	-	386.3	(9.1)	377.2
Operating income	-	-	266.0	-	266.0
Other deductions (income):					
Interest expense	0.2	107.8	23.7	(70.7)	61.0
Interest income	(30.0)	(20.0)	(42.2)	70.7	(21.5)
Equity in earnings of subsidiaries	(197.9)	(285.7)	-	483.6	-
Miscellaneous other income	-	-	(2.0)	-	(2.0)
	(227.7)	(197.9)	(20.5)	483.6	37.5
					-
Income before income taxes	227.7	197.9	286.5	(483.6)	228.5
Income Taxes	-	-	0.8	-	0.8
Net Income	$ 227.7	$ 197.9	$ 285.7	$ (483.6)	$ 227.7

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	-
Notes receivable from affiliates	-	153.2	-	(153.2)	-
Sale 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 note 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)
Capital contribution from general partner	6.8	-	-	-	6.8
Advances from affiliates, net	-	64.9	248.7	(313.6)	-
Proceeds from sale of common units, net of related transaction costs	326.3	-	-	-	326.3
Net Cash Provided by (Used in) 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	-
Notes receivable from affiliates	-	(153.2)	-	153.2	-
Purchases of short-term investments	-	(175.0)	-	-	(175.0)
Net Cash (Used in) Provided by 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)
Capital contribution from general partner	29.2	-	-	-	29.2
Advances from affiliates, net	(1,504.0)	(32.2)	-	1,536.2	-
Proceeds from sale of class B units	686.0	-	-	-	686.0
Proceeds from sale of common units, net of related transaction costs	733.6	-	-	-	733.6
Net Cash Provided by (Used in) 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

Condensed Consolidating Statements of Cash Flow for the Year Ended December 31, 2007
(in millions)

	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Net Cash Provided by (Used In) Operating Activities	$ 225.9	$ (90.7)	$ 344.4	$ (197.9)	$ 281.7
Investing Activities:					
Capital expenditures	-	-	(1,210.7)	0.9	(1,209.8)
Proceeds from sale of operating assets, net	-	-	28.7	-	28.7
Proceeds from insurance reimbursements and other recoveries	-	-	1.7	-	1.7
Advances to affiliates, net	(554.6)	(1.6)	204.4	350.9	(0.9)
Distribution from consolidated subsidiary	7.1	-	-	(7.1)	-
Investment in consolidated subsidiary	-	(135.9)	-	135.9	-
Net Cash (Used in) Provided by Investing Activities	(547.5)	(137.5)	(975.9)	480.6	(1,180.3)
Financing Activities:					
Proceeds from long-term debt, net of issuance costs	-	-	495.3	-	495.3
Contribution from parent	-	-	135.9	(135.9)	-
Distributions paid	(205.0)	(205.0)	-	205.0	(205.0)
Capital contribution from general partner	10.7	-	-	-	10.7
Advances from affiliates, net	-	351.8	-	(351.8)	-
Proceeds from sale of common units, net of related transaction costs	515.9	-	-	-	515.9
Net Cash Provided by Financing Activities	321.6	146.8	631.2	(282.7)	816.9
Decrease in Cash and Cash Equivalents	-	(81.4)	(0.3)	-	(81.7)
Cash and Cash Equivalents at Beginning of Period	-	398.2	0.8	-	399.0
Cash and Cash Equivalents at End of Period	$ -	$ 316.8	$ 0.5	$ -	$ 317.3

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 of the end of the period covered by this report. The CEO and CFO have concluded that our controls and procedures were effective as of December 31, 2009.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2009, 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, 2009. 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, 2009, 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, 2009, 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, 2009, 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, 2009 of the Partnership and our report dated February 16, 2010 expressed an unqualified opinion on those financial statements and financial statement schedule.

DELOITTE & TOUCHE LLP
Houston, Texas
February 16, 2010

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	56	Chief Executive Officer, President and Director
Jamie L. Buskill	45	Chief Financial Officer, Senior Vice President and Treasurer
Brian A. Cody	52	Chief Operating Officer
Michael E. McMahon	54	Senior Vice President, General Counsel and Secretary
Arthur L. Rebell	69	Director, Chairman of the Board
Kenneth I. Siegel	52	Director
William R. Cordes	61	Director
Thomas E. Hyland	64	Director
Jonathan E. Nathanson	48	Director
Mark L. Shapiro	65	Director
Andrew H. Tisch	60	Director

All directors have served since 2005 except for Mr. Cordes and Mr. Siegel who were elected to the Board in October 2006 and 2009, respectively. All directors serve until replaced or upon their voluntary resignation.

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. During that time he also served in various management roles for affiliates of Gulf South, including President of Koch Power, Inc., Managing Director of Koch Energy International and Vice President of Corporate Development for Koch Energy, Inc. 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—In February 2009, Mr. Cody was appointed Chief Operating Officer of BGL. Prior to the appointment, Mr. Cody had been the Chief Commercial Officer of BGL since March 2007. Mr. Cody has 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 Interstate Natural Gas Association of America and the American Gas Association.

Arthur L. Rebell—Mr. Rebell has been employed as an executive of Loews since 1998 including as Senior Vice President from 1998 through 2009. Mr. Rebell also serves as a director for 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 currently a private investor and is also a member of the board of Kayne Anderson Energy Development Company. Mr. Cordes brings significant pipeline industry experience as well as his extensive business and management expertise to the Company 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 is currently a private investor. Mr. Hyland was selected to serve as a director on our Board due to his extensive background in public accounting and auditing. Mr. Hyland qualifies 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 financial expertise.

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 2009, in a timely manner.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Overview

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 the Partnership and our unitholders, 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 combines elements of base salary and cash and equity-based incentive compensation, as well as retirement and other benefits. We have selected these elements and otherwise structured our executive compensation practices to align the interests of our executives with those of our unitholders and our general partner, retain our executives and appropriately reward their performance both in the long and short-term. In the development of our executive compensation programs, particularly with regard to our equity-based compensation plans, we 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 also considered the historical compensation policies and practices of our operating subsidiaries, as well as applicable tax and accounting impacts of executive compensation, including the tax implications of providing equity-based compensation to our employees in light of our being a limited partnership. In developing our compensation plans, no benchmarking of total compensation, or any element of compensation, was performed against any particular reference group of companies. During 2009, we did not engage a compensation consultant to provide recommendations on the amount and form of executive officer compensation, nor did a compensation consultant otherwise provide executive compensation services to the Partnership.

As discussed elsewhere in this Report, our Board of Directors (Board) does not have a Compensation Committee. Therefore, the compensation for Rolf Gafvert, our Chief Executive Officer (CEO) (principal executive officer (PEO)), Jamie L. Buskill, our Chief Financial Officer (CFO) (principal financial officer (PFO)) and our two other most highly compensated named executive officers, 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.

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

- base salary;
- annual incentive compensation awards, including cash bonuses and grants of phantom common units (Phantom Common Units) under our Long-Term Incentive Plan (LTIP);
- annual grants of phantom general partner units (Phantom GP Units) under our Strategic Long-Term Incentive Plan (SLTIP); and
- retirement, medical and related benefits.

As discussed in more detail below, in setting compensation policies and making compensation decisions for our Named Executive Officers, our Board typically considers certain financial measures, operating goals and progress made on key projects. However, we do not use formula-driven plans when determining the aggregate amount of compensation for each Named Executive Officer. Our Board considers a number of factors in making its determinations of executive compensation, including compensation paid in prior years, whether the financial measures, operating goals and project progress were achieved and the individual contributions of each executive to our overall business success for the year. However, the final amount of any payout is discretionary, is based on the business judgment of our Board and is not generated or calculated by reference to any particular performance metric.

Base Salary

Our executive compensation policies emphasize the incentive-based compensation elements discussed below. In determining the amount of base salary, 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. In 2009, the base salary of Mr. Cody was increased approximately 6% reflecting his promotion to chief operating officer. The base salaries of our other Named Executive Officers were not changed during 2009.

Incentive Compensation – Cash Bonuses and Phantom Common Unit Awards

Our incentive compensation programs, and the compensation awarded under them, are discretionary and are not formulaic in nature. In the context of performance and past compensation policies and practices, the Board considers individual performance factors that include the Board's view of the performance of the individual, the responsibilities of the individual's position and the individual's contribution to the Partnership and to the financial and operational performance for the most recently completed fiscal year. There is no specific weighting given to each factor, but rather the Board considers and balances these factors in its judgment and discretion.

Cash Bonuses. A significant portion of the compensation of our Named Executive Officers consists of an annual incentive compensation award, which is an aggregate dollar amount determined by our Board. The annual incentive compensation award has traditionally been paid in part as a cash bonus and in part as an award of Phantom Common Units though the Board retains discretion in making that determination. In 2009, the Board exercised its discretion by awarding only cash bonuses to the Named Executive Officers for the reasons described below. No Phantom Common Units were awarded in 2009.

At the beginning of a year, the Board establishes, based upon a recommendation by the CEO, a potential bonus pool for our employees as a whole, including the Named Executive Officers. Certain financial or operating measures are established by the Board to be used as guidelines in determining, at year end, the final amount of the pool and individual bonus awards. These measures are not firm targets or goals that must be achieved in order for payouts from the bonus pool to be made; rather the Board considers these measures, based upon recommendations by the CEO, in determining whether to adjust the size of the bonus pool at the end of the year and in awarding individual payments from the pool. At the end of the year, the CEO makes recommendations to the Board regarding the size of the final bonus pool and amounts to pay Named Executive Officers and other employees, taking into consideration actual results as compared to the measures set at the beginning of the year, the individual performance and contributions to the Partnership of each Named Executive Officer and other factors deemed relevant. The amounts of the bonus pool and any individual awards are discretionary based on the judgment of the CEO and the Board. Any bonus paid to the CEO is determined by the Board based upon a similar review of his performance and contributions.

For 2009, the financial and operating measures that were established by the Board were:

- Achieving 2009 EBITDA, as defined in Item 6, *Non-GAAP Financial Measure*, adjusted for expected unusual items, of $598.8 million and declaring annual distributions with respect to 2009 of $1.97 per unit;
- Operating a safe, reliable pipeline system;
- Timely completion of our announced pipeline expansion projects within budget; and
- Contracting the available capacity of our expansion projects and renegotiating or replacing expiring contracts on our existing pipelines for longer terms and at favorable rates.

For 2009, the Board determined that we met our goals regarding safety, contracting and placing in service the compression assets related to our expansion projects. However, although we met the financial measure of declaring distributions to unitholders of $1.97 per unit with respect to 2009, our reported EBITDA of $498.0 million for the 2009 period was significantly lower than the measure established for the year of $598.8 million. The difference in EBITDA was primarily driven by lowering operating pressures on our expansion pipelines due to pipe anomalies and shutting down those pipelines for periods of time for the remediation of those anomalies, partly offset by favorable performance for our parking and lending and storage services. Taking into account the results for the year against the various measures established, the Board decided to reduce the total amount of compensation awarded to the Named Executive Officers for 2009. Although each Named Executive Officer was awarded a higher amount of cash bonus than was awarded in 2008, the Board decided that it would not make any awards of Phantom Common Units or Phantom GP Units, which are both described below. In making that decision, our CEO and the Board considered the factors listed above with particular emphasis on the shortfall in the expected amount of EBITDA. The amounts awarded to the Named Executive Officers are set forth in the Summary Compensation Table below.

Phantom Common Units. We are a limited partnership. If our Named Executive Officers owned our units directly, they would be subject to significant adverse individual tax consequences, such as being taxed on all income as partners rather than employees. Furthermore, the ownership of units by our executives would negatively impact the tax status of our benefit plans. As a result, we award our executives equity-based compensation in the form of Phantom Common Units. The economic value of these awards is directly tied to the value of our common units, but these awards do not confer any rights of ownership to the grantee. The value of a Phantom Common Unit is equal to the value of a common unit plus accumulated distributions made on such common unit since the award date. That value is paid to the executive by us in cash at the end of a vesting period if the executive is still employed on the vesting date. Our Board has discretion to determine the amount, vesting schedule and certain other terms of awards under our LTIP. For the reasons described under *Cash Bonuses*, no Phantom Common Units were awarded to the Named Executive Officers in 2009.

Phantom GP Units. In previous years, our Board has also made awards of Phantom GP Units to our Named Executive Officers. These awards give the grantee an economic interest in the performance of our general partner, including our general partner's incentive distribution rights, but do not confer any right of ownership of our general partner to the grantee. Phantom GP Units provide the holder with an opportunity, subject to vesting, to receive a lump sum cash payment in an amount determined under a formula based on the amount of cash distributions made by us to our general partner during the four quarters preceding the vesting date and the implied yield on our common units, up to a maximum of $50,000 per unit. For the reasons described under *Cash Bonuses*, no Phantom GP Units were awarded to the Named Executive Officers in 2009.

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 others participate 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. Certain Named Executive Officers are also eligible for retiree medical benefits after reaching age 55 as part of a plan offered to Texas Gas employees.

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 ownership of our equity by our management. We therefore seek to align the interests of management with our unitholders by granting the Phantom Common Units and Phantom GP Units. Although no awards of Phantom Common Units and Phantom GP Units were made in 2009, we believe that previous years' awards that are currently unvested achieve this objective.

All Other Compensation

There were no other material perquisites or personal benefits paid to our Named Executive Officers in 2009.

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 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 2009, 2008 or 2007.

Executive Compensation

Summary of Executive Compensation

The following table shows a summary of total compensation earned by our Named Executive Officers during 2009, 2008 and 2007:

Summary Compensation Table for 2009

Name and Principal Position	Year	Salary (1) ($)	Bonus ($)	Stock Awards (2) ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
Rolf A. Gafvert, CEO (PEO)							
	2009	**337,500**	**450,000**	**-**	**-**	**33,842 (3)**	**821,342**
	2008	325,000	300,000	1,424,997	-	33,589	2,083,586
	2007	323,365	300,000	1,450,010	-	35,360	2,108,735
Jamie L. Buskill, CFO (PFO)							
	2009	**311,538**	**275,000**	**-**	**91,527 (4)**	**17,085 (5)**	**695,150**
	2008	292,500	150,000	675,000	43,464	23,934	1,184,898
	2007	225,000	225,000	600,000	46,602	14,386	1,110,988
Brian A. Cody, Chief Operating Officer							
	2009	**262,500**	**300,000**	**-**	**-**	**28,118 (6)**	**590,618**
	2008	240,000	200,000	675,000	-	27,615	1,142,615
	2007	228,846	175,000	600,005	-	23,107	1,026,958
Michael E. McMahon, Senior Vice President, General Counsel and Secretary							
	2009	**249,231**	**275,000**	**-**	**-**	**26,928 (7)**	**551,159**
	2008	230,769	200,000	650,000	-	20,666	1,101,435
	2007	216,346	125,000	550,005	-	28,938	920,289

(1) The 2009 payroll cycle contained one additional pay period as compared to 2008, resulting in more salary paid to the Named Executive Officers in 2009.

(2) The amounts reflected in this column represent the aggregate grant date fair value for grants during the fiscal year. Note 9 in Item 8 of this Report contains information regarding the assumptions we made in determining these values.

(3) 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.

(4) Includes the change in qualified retirement plan account balance ($56,446) and interest and pay credits for the supplemental retirement plan ($35,081).

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

(6) 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.

(7) 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.

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 Salary and Bonus Paid to Total Compensation**
Rolf A. Gafvert	**2009**	**96%**
	2008	30%
	2007	30%
Jamie L. Buskill	**2009**	**84%**
	2008	37%
	2007	41%
Brian A. Cody	**2009**	**95%**
	2008	39%
	2007	39%
Michael E. McMahon	**2009**	**95%**
	2008	39%
	2007	37%

Grants of Plan-Based Awards

There were no awards granted in 2009 to our Named Executive Officers under our LTIP or SLTIP as discussed under *Incentive Compensation – Cash Bonuses and Phantom Common Unit Awards.*

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

We do not have employment agreements with any of our Named Executive Officers. With respect to our equity awards, each grant of the Phantom Common Units 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, less applicable taxes. The vesting period of the Phantom GP units is 4.0 years from the initial date of grant. Note 9 in Item 8 of this Report contains more information regarding our LTIP and SLTIP.

For more information about the components of compensation reported in the Summary Compensation Table, please read the *Compensation Discussion and Analysis* above.

Outstanding Equity Awards at Fiscal Year-End

The table displayed below shows the total number of outstanding equity awards in the form of 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, 2009:

Outstanding Equity Awards at December 31, 2009

Stock Awards			
Name	Plan Name	**Number of Shares or Units that Have Not Vested (1) (#)**	**Market Value of Shares or Units of Stock that Have not Vested (2)(3) ($)**
Rolf A. Gafvert	LTIP	11,981	359,789
	SLTIP	100	3,026,798
Jamie L. Buskill	LTIP	3,735	112,162
	SLTIP	46	1,392,327
Brian A. Cody	LTIP	5,368	161,201
	SLTIP	49	1,483,131
Michael E. McMahon	LTIP	4,123	123,814
	SLTIP	43	1,301,523

(1) There were no grants of Phantom Common Units or Phantom GP Units under our LTIP and SLTIP awarded to Messrs. Gafvert, Buskill, Cody and McMahon in 2009. On December 16, 2008, Messrs. Gafvert, Buskill, Cody, and McMahon were awarded grants of Phantom Common Units under our LTIP of 8,715, 3,735, 3,735 and 2,490 and Phantom GP Units under our SLTIP in the amount of 25, 12, 12, and 12. On December 14, 2007, Messrs. Gafvert, Buskill, Cody and McMahon were awarded grants of Phantom Common Units under our LTIP of 6,532, 0, 3,266 and 3,266 and Phantom GP Units under our SLTIP in the amount of 25, 12, 10 and 12. On December 20, 2006, Messrs. Gafvert and Buskill were awarded grants of Phantom Common Units under our LTIP of 6,427 and 1,205 and Phantom GP Units under our SLTIP in the amount of 25 and 10.

(2) The market value per unit reported in the above table is based on the NYSE closing market price on December 31, 2009 of $30.03.

(3) In addition to the Phantom Common Units, Messrs. Gafvert, Buskill, Cody and McMahon have accumulated non-vested amounts related to the DER that are tandem grants to the Phantom Common Units. Such DER amounts for Messrs. Gafvert, Buskill, Cody, and McMahon were $29,470, $7,283, $13,521 and $11,094 in 2009.

Option Exercises and Stock Vested

The following table presents information regarding the vesting during 2009 of Phantom Common Units and Phantom GP Units previously granted to the Named Executive Officers. We have not issued any awards in the form of options on our units to any employees, including Named Executive Officers.

Option Exercises and Stock Vested for 2009

	Stock Awards			
Name	**Number of LTIP Awards Vesting (#)**	**Value Received on Vesting (1) ($)**	**Number of SLTIP Awards Vesting (#)**	**Value Received on Vesting ($)**
Rolf A. Gafvert	6,479	221,063	-	-
Jamie L. Buskill	602	21,097	-	-
Brian A. Cody	3,239	110,514	-	-
Michael E. McMahon	3,239	110,514	-	-

(1) The LTIP awards vested in December 2009 and were paid out as a lump sum cash payment in January 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 2009 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 2009

Name	**Plan Name**	**Number of Years Credited Service (#)**	**Present Value of Accumulated Benefit ($)**	**Payments During Last Fiscal Year ($)**
Jamie L. Buskill	TGRP	23.3	242,555	-
	SRP	23.3	100,566	-

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. 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.

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 2009. 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, 2009, commencing in 2010, 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, 2009, 2008 and 2007 were 4.27%, 4.27% and 4.79% and for future years, 4.19%, 4.27% and 4.50%. The future normal retirement date accumulated cash balance is then discounted using an interest rate at December 31, 2009, 2008 and 2007 of 5.70%, 6.30% and 6.00%. The increase in the present value of accumulated benefit for the TGRP between December 31, 2009 and 2008 of $56,446 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 for participating employees for earnings that exceed the IRC compensation limitations for qualified defined benefit plans. 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 years for Mr. Buskill is reported as compensation in the Summary Compensation Table above.

Potential Payments Upon Termination or Change of Control

We do not govern the Named Executive Officer's employment relationships with formal employment agreements, though they are eligible to receive accelerated vesting of equity awards under certain of our compensation plans. We have made grants of Phantom Common Units and Phantom GP Units to each of our executives subject to specific vesting schedules and payment limitations, as discussed above. Each of these equity 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.

Long-Term Incentive Plan. The Phantom Common Units generally vest over a three-year period; the first 50% will vest upon the second anniversary of the grant date, while the remaining 50% will vest on the third anniversary of the grant date. 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, 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.

Strategic Long-Term Incentive Plan. Phantom GP Units do not provide for distribution equivalent rights as do the Phantom Common Units. Our SLTIP requires a minimum distribution amount per unit to be met prior to any payment on a Phantom GP Unit, otherwise the Phantom GP Unit will be forfeited without payment. Phantom GP Unit payments may be made in amounts equal to the product of the "formula value" of the units and the number of units held on the vesting date. The "formula value" under the SLTIP means the lesser of (a) 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; or (b) $50,000. As our general partner met its minimum distribution amount for the 2009 year, 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 2009 year, up to a two week maximum for employees of Texas Gas and a one week maximum for Gulf South employees.

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, 2009. The closing price of our common units on the NYSE on December 31, 2009, $30.03, was used to calculate these amounts.

Potential Payments Upon Termination or Change of Control at December 31, 2009

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	LTIP (3)	389,260	389,260	-	389,260	389,260
	SLTIP (4)	3,026,798	3,026,798	-	3,026,798	3,026,798
	PTO (5)	-	-	-	-	-
	Total	3,416,058	3,416,058	-	3,416,058	3,416,058
Jamie L. Buskill (6)	LTIP (3)	119,445	119,445	-	119,445	119,445
	SLTIP (4)	1,392,327	1,392,327	-	1,392,327	1,392,327
	PTO (5)	11,538	11,538	11,538	11,538	11,538
	Total	1,523,310	1,523,310	11,538	1,523,310	1,523,310
Brian A. Cody	LTIP (3)	174,722	174,722	-	174,722	174,722
	SLTIP (4)	1,483,131	1,483,131	-	1,483,131	1,483,131
	PTO (5)	-	-	-	-	-
	Total	1,657,853	1,657,853	-	1,657,853	1,657,853
Michael E. McMahon	LTIP (3)	134,907	134,907	-	134,907	134,907
	SLTIP (4)	1,301,523	1,301,523	-	1,301,523	1,301,523
	PTO (5)	9,231	9,231	9,231	9,231	9,231
	Total	1,445,661	1,445,661	9,231	1,445,661	1,445,661

(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 LTIP and SLTIP as age 65 or older, although a participant in the plan can become fully vested in outstanding awards at age 60 with Board approval. Retirement of a participant prior to age 60 would result in the forfeiture of outstanding awards. As of December 31, 2009, none of the named executive officers were eligible for retirement as defined in the LTIP and the SLTIP.

(3) LTIP amounts were determined by multiplying the number of unvested Phantom Common Units each executive held on December 31, 2009, by the value of our common units on that date, or $30.03. 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, 2009, Messrs. Gafvert, Buskill, Cody and McMahon held Phantom Common Units of 11,981, 3,735, 5,368 and 4,123, respectively. The amount of DERs accrued for these units were for Messrs. Gafvert, Buskill, Cody and McMahon, $29,470, $7,283, $13,521 and $11,094, respectively.

(4) SLTIP amounts were determined by multiplying the number of unvested Phantom GP Units each executive held on December 31, 2009, by the value of each GP unit on that date ($30,268) 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, 2009, of $20.0 million and an implied yield on our common units of 6.59% at December 31, 2009. As of December 31, 2009, Messrs. Gafvert, Buskill, Cody and McMahon held 100, 46, 49, and 43 Phantom GP Units, respectively.

(5) Includes earned but unused vacation at December 31, 2009.

(6) 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 above.

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 chair 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 2009:

Director Compensation for 2009

Name	Fees Earned or Paid in Cash ($)	Stock Awards (1) ($)	Total ($)
William R. Cordes	36,250	10,290	46,540
Thomas E. Hyland (2)	45,000	10,290	55,290
Mark L. Shapiro	36,250	10,290	46,540

(1) On March 5, 2009, Messrs. Cordes, Hyland and Shapiro were each granted 500 common units. The grant date fair value of each unit award, based on the closing market price of $20.58, was $10,290. Note 9 in Item 8 of this Report contains information regarding the assumptions we made in determining these values.

(2) Chair of the Audit Committee.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information, at February 10, 2010, 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	1,500	*	-	-	*
Rolf A. Gafvert	-	-	-	-	-
Thomas E. Hyland	7,400 (2)	*	-	-	*
Michael E. McMahon	-	-	-	-	-
Jonathan E. Nathanson	15,000	*	-	-	*
Arthur L. Rebell	39,083 (3)	*	-	-	*
Mark L. Shapiro	12,000	*	-	-	*
Kenneth I. Siegel	-	-	-	-	-
Andrew H. Tisch	81,050 (4)	*	-	-	*
All directors and executive officers as a group	156,033	*	-	-	-
BPHC (5)	114,219,466	67%	22,866,667	100%	71%
Loews Corporation (5)	114,219,466	67%	22,866,667	100%	71%

*Represents less than 1% of the outstanding common units

(1) As of February 10, 2010, 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 72% 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, 2009, 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	**3,519,500**

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 2009 nor were there any service transactions where the policy was not followed.

In 2009, we issued 6.7 million common units to BPHC resulting in net proceeds of $150.0 million, and entered into a Subordinated Loan Agreement with BPHC under which Boardwalk Pipelines borrowed $200.0 million. In connection with the issuance of common units, we amended our Registration Rights Agreement with BPHC to increase from 21.2 million to 27.9 million the number of units for which we have agreed to reimburse BPHC for underwriting discounts and commissions associated with the resale of common units by BPHC, up to a maximum of $0.914 per common unit. These transactions were subject to review and approval by our Board, including separate approval by our Conflicts Committee. Distributions are approved by the Board on a quarterly basis prior to declaration. Note 7 and Note 16 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 2009 and 2008 by category as described in the notes to the table (in millions):

	2009	2008
Audit fees (1)	**$ 2.0**	$ 1.9
Audit related fees (2)	**0.1**	0.5
Total	**$ 2.1**	$ 2.4

(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, including, principally, consents and 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, 2009 and 2008

Consolidated Statements of Income for the years ended December 31, 2009, 2008 and 2007

Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008 and 2007

Consolidated Statements of Changes in Partners' Capital for the years ended December 31, 2009, 2008 and 2007

Consolidated Statements of Comprehensive Income for the years ended December 31, 2009, 2008 and 2007

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, 2009, 2008 and 2007 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:					
2009	**$ 0.3**	**$ 0.3**	**$ -**	**$ (0.3)**	**$ 0.3**
2008	0.4	-	(0.1)	-	0.3
2007	2.6	2.7	(4.7)	(0.2)	0.4
Inventory obsolescence:					
2009	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
2008	0.1	-	-	(0.1)	-
2007	-	-	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 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).

4.12 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).

4.13 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	Loan Agreement, dated December 1, 2008, Mississippi Business Finance Corporation and Gulf South Pipeline Company, LP (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on December 9, 2008).
10.11	Bond Purchase Agreement, dated December 1, 2008, among Boardwalk Pipelines, LP, Mississippi Business Finance Corporation and Gulf South Pipeline Company, LP (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on December 9, 2008).
10.12	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.
*23.0	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 16, 2010 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 16, 2010	/s/ Rolf A. Gafvert Rolf A. Gafvert President, Chief Executive Officer and Director (principal executive officer)
Dated: February 16, 2010	/s/ Jamie L. Buskill Jamie L. Buskill Senior Vice President, Chief Financial Officer and Treasurer (principal financial officer)
Dated: February 16, 2010	/s/ Steven A. Barkauskas Steven A. Barkauskas Vice President, Controller and Chief Accounting Officer (principal accounting officer)
Dated: February 16, 2010	/s/ William R. Cordes William R. Cordes Director
Dated: February 16, 2010	/s/ Thomas E. Hyland Thomas E. Hyland Director
Dated: February 16, 2010	/s/ Jonathan E. Nathanson Jonathan E. Nathanson Director
Dated: February 16, 2010	/s/ Arthur L. Rebell Arthur L. Rebell Director
Dated: February 16, 2010	/s/ Mark L. Shapiro Mark L. Shapiro Director
Dated: February 16, 2010	/s/ Kenneth I. Siegel Kenneth I. Siegel Director
Dated: February 16, 2010	/s/ Andrew H. Tisch Andrew H. Tisch Director

EXHIBIT 21.1

BOARDWALK PIPELINE PARTNERS, LP
Subsidiaries of the Registrant
December 31, 2009

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 23.0

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-141058 on Form S-3 of our reports dated February 16, 2010, 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, 2009.

DELOITTE & TOUCHE LLP
Houston, Texas
February 16, 2010

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 16, 2010

/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 16, 2010

/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, 2009, (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 16, 2010

/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, 2009, (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 16, 2010

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