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

FORM 10-Q

(Mark One)
☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2007

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.)

3800 Frederica Street, Owensboro, Kentucky 42301
(270) 926-8686
(Address and Telephone Number of Registrant's Principal Executive Office)

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (check one:)

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

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

As of July 20, 2007, the registrant had 83,156,122 common units outstanding and 33,093,878 subordinated units outstanding.

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PART I – FINANCIAL INFORMATION

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BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED BALANCE SHEETS
(Thousands of Dollars)
(Unaudited)

ASSETS	June 30, 2007	December 31, 2006
Current Assets:		
Cash and cash equivalents	$ 387,746	$ 399,032
Receivables:		
Trade, net	41,581	54,082
Other	6,405	12,759
Gas Receivables:		
Transportation and exchange	11,185	9,115
Storage	16	11,704
Inventories	14,062	14,110
Costs recoverable from customers	7,381	11,236
Gas stored underground	12,108	14,001
Prepaid expenses and other current assets	18,320	22,117
Total current assets	498,804	548,156
Property, Plant and Equipment:		
Natural gas transmission plant	2,359,683	1,997,922
Other natural gas plant	229,146	213,926
	2,588,829	2,211,848
Less—Accumulated depreciation and amortization	225,033	187,412
Property, plant and equipment, net	2,363,796	2,024,436
Other Assets:		
Goodwill	163,474	163,474
Gas stored underground	174,570	161,537
Costs recoverable from customers	16,428	19,767
Other	29,818	33,929
Total other assets	384,290	378,707
Total Assets	$ 3,246,890	$ 2,951,299

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

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED BALANCE SHEETS
(Thousands of Dollars, except number of units)
(Unaudited)

LIABILITIES AND PARTNERS' CAPITAL	June 30, 2007	December 31, 2006
Current Liabilities:		
Payables:		
Trade	$ 54,549	$ 56,604
Affiliates	813	3,014
Other	14,333	14,459
Gas Payables:		
Transportation and exchange	19,508	15,485
Storage	40,047	42,127
Other accrued taxes	27,977	16,082
Accrued interest	19,621	19,376
Accrued payroll and employee benefits	16,141	18,198
Deferred income	5,193	22,147
Other current liabilities	17,483	20,926
Total current liabilities	215,665	228,418
Long –Term Debt	1,351,384	1,350,920
Other Liabilities and Deferred Credits:		
Pension and postretirement benefits	17,271	15,761
Asset retirement obligation	14,668	14,307
Provision for other asset retirement	40,924	39,644
Other	26,245	29,742
Total other liabilities and deferred credits	99,108	99,454
Commitments and Contingencies		
Partners' Capital:		
Common units - 83,156,122 units and 75,156,122 units issued and outstanding as of June 30, 2007 and December 31, 2006	1,241,806	941,792
Subordinated units - 33,093,878 units issued and outstanding as of June 30, 2007 and December 31, 2006	291,148	285,543
General partner	28,381	22,060
Accumulated other comprehensive income	19,398	23,112
Total partners' capital	1,580,733	1,272,507
Total Liabilities and Partners' Capital	$ 3,246,890	$ 2,951,299

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

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Thousands of Dollars, except number of units and per unit amounts)
(Unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2007	2006	2007	2006
Operating Revenues:				
Gas transportation	$ 115,008	$ 105,390	$ 267,922	$ 256,402
Parking and lending	12,796	9,414	31,178	22,931
Gas storage	10,489	7,196	18,199	16,814
Other	12,249	6,662	21,355	6,961
Total operating revenues	150,542	128,662	338,654	303,108
Operating Costs and Expenses:				
Operation and maintenance	42,995	36,833	82,454	75,160
Administrative and general	22,116	22,844	47,909	50,232
Depreciation and amortization	20,219	18,727	40,134	37,410
Taxes other than income taxes	7,209	6,785	15,169	12,014
Asset impairment	14,698	-	14,698	-
Net (gain) loss on disposal of operating assets and related contracts	(1,001)	(2,391)	1,638	(2,205)
Total operating costs and expenses	106,236	82,798	202,002	172,611
Operating income	44,306	45,864	136,652	130,497
Other Deductions (Income):				
Interest expense	14,548	15,215	31,345	30,847
Interest income	(5,968)	(698)	(10,542)	(1,242)
Interest income from affiliates, net	(13)	(7)	(20)	(7)
Miscellaneous other deductions (income), net	159	(792)	(175)	(977)
Total other deductions	8,726	13,718	20,608	28,621
Income before income taxes	35,580	32,146	116,044	101,876
Income taxes	132	246	362	246
Net income	$ 35,448	$ 31,900	$ 115,682	$ 101,630

Calculation of limited partners' interest in Net income:

Net income	$ 35,448	$ 31,900	$ 115,682	$ 101,630
Less general partner's interest in Net income	1,199	638	3,010	2,033
Limited partners' interest in Net income	$ 34,249	$ 31,262	$ 112,672	$ 99,597
Basic and diluted net income per limited partner unit:				
Common units	$ 0.35	$ 0.35	$ 0.97	$ 0.95
Subordinated units	$ 0.17	$ 0.22	$ 0.97	$ 0.95
Cash distribution to common and subordinated unitholders	$ 0.43	$ 0.36	$ 0.845	$ 0.54
Weighted-average number of limited partner units outstanding:				
Common units	83,156,122	68,256,122	79,576,012	68,256,122
Subordinated units	33,093,878	33,093,878	33,093,878	33,093,878

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

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Thousands of Dollars)
(Unaudited)

	For the Six Months Ended June 30, 2007	2006
OPERATING ACTIVITIES:		
Net income	$ 115,682	$ 101,630
Adjustments to reconcile to cash provided by operations:		
Depreciation and amortization	40,134	37,410
Amortization of deferred costs	3,803	1,106
Amortization of acquired executory contracts	(889)	(2,561)
Asset impairment	14,698	-
Loss (gain) on disposal of operating assets	1,638	(2,205)
Changes in operating assets and liabilities:		
Trade and other receivables	17,129	12,791
Gas receivables and storage assets	(1,887)	22,178
Costs recoverable from customers	4,281	4,065
Other assets	(6,129)	(10,232)
Trade and other payables	(11,632)	7,643
Gas payables	(5,350)	(44,050)
Accrued liabilities	10,084	(8,262)
Other liabilities	(9,896)	17,028
Net cash provided by operating activities	171,666	136,541
INVESTING ACTIVITIES:		
Capital expenditures	(380,062)	(55,200)
Proceeds from sale of operating assets	328	4,178
Proceeds from insurance reimbursements and other recoveries	1,726	4,960
Advances to affiliates, net	(1,202)	(623)
Net cash used in investing activities	(379,210)	(46,685)
FINANCING ACTIVITIES:		
Payments of notes payable	-	(42,100)
Distributions	(97,559)	(55,722)
Proceeds from sale of common units, net of related transaction costs	287,858	13
Capital contribution from general partner	5,959	-
Net cash provided by (used in) financing activities	196,258	(97,809)
Increase (decrease) in cash and cash equivalents	(11,286)	(7,953)
Cash and cash equivalents at beginning of period	399,032	65,792
Cash and cash equivalents at end of period	$ 387,746	$ 57,839

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

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(Thousands of Dollars, except units)
(Unaudited)

	Common Units	Subordinated Units	General Partner	Accumulated Other Comprehensive (Loss) Income	Total Partners' Capital
Balance, January 1, 2006	$ 705,609	$ 266,578	$ 16,661	$ (174)	$ 988,674
Add (deduct):					
Net income	67,075	32,522	2,033	-	101,630
Distributions paid	(36,776)	(17,831)	(1,115)	-	(55,722)
Other comprehensive income	-	-	-	4,814	4,814
Transaction costs related to sale of common units	13	-	-	-	13
Balance, June 30, 2006	$ 735,921	$ 281,269	$ 17,579	$ 4,640	$ 1,039,409
Balance, January 1, 2007	$ 941,792	$ 285,543	$ 22,060	$ 23,112	$ 1,272,507
Add (deduct):					
Net income	79,103	33,569	3,010	-	115,682
Distributions paid	(66,947)	(27,964)	(2,648)	-	(97,559)
Other comprehensive income	-	-	-	(3,714)	(3,714)
Sale of common units, net of related transaction costs (8,000,000 units)	287,858	-	-	-	287,858
Capital contribution from general partner	-	-	5,959	-	5,959
Balance, June 30, 2007	$ 1,241,806	$ 291,148	$ 28,381	$ 19,398	$ 1,580,733

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

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Thousands of Dollars)
(Unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2007	**2006**	**2007**	**2006**
Net income	$ 35,448	$ 31,900	$ 115,682	$ 101,630
Other comprehensive income:				
Gain (Loss) on cash flow hedges	8,433	3,390	896	10,408
Reclassification adjustment transferred to Net income	(3,061)	(2,802)	(4,610)	(5,594)
Total comprehensive income	$ 40,820	$ 32,488	$ 111,968	$ 106,444

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

Note 1: Basis of Presentation

Boardwalk Pipeline Partners, LP (the Partnership) is a Delaware limited partnership formed to own and operate the business conducted by Boardwalk Pipelines, LP (Boardwalk Pipelines) and its subsidiaries, Gulf South Pipeline Company, LP (Gulf South) and Texas Gas Transmission, LLC (Texas Gas) (together, the operating subsidiaries). The Partnership is a 74.8%-owned subsidiary of Boardwalk Pipelines Holding Corp. (BPHC), which is wholly owned by Loews Corporation (Loews).

The accompanying unaudited condensed consolidated financial statements of the Partnership were prepared pursuant to the rules and regulations of the United States Securities and Exchange Commission (SEC). Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) have been condensed or omitted pursuant to such rules and regulations. In the opinion of management, the accompanying condensed consolidated financial statements reflect all adjustments (consisting of only normal recurring accruals) necessary to present fairly the financial position as of June 30, 2007 and December 31, 2006, and the results of operations for the three and six months ended June 30, 2007 and 2006 and changes in cash flow for the six months ended June 30, 2007 and 2006. Reference is made to the Notes to Consolidated Financial Statements in the 2006 Annual Report on Form 10-K, which should be read in conjunction with these unaudited condensed consolidated financial statements. The accounting policies described in Note 2 to the Consolidated Financial Statements included in such Annual Report on Form 10-K are the same used in preparing the accompanying unaudited condensed consolidated financial statements.

Net income for interim periods may not necessarily be indicative of results for the calendar year. All significant intercompany items have been eliminated in consolidation. Certain reclassifications have been made to the 2006 financial statements to conform to the 2007 presentation, primarily related to individual amounts and captions within the Operating Activities section of the Condensed Consolidated Statements of Cash Flows.

Note 2: Gas in Storage and Gas Receivables/Payables

Gas receivables and payables reflect amounts of customer-owned gas at the Texas Gas facilities. Consistent with the method of storage accounting elected by Texas Gas and the risk-of-loss provisions included in its tariff, Texas Gas reflects an equal and offsetting receivable and payable for customer-owned gas in its facilities for storage and related services. The gas payables amount is reflected in Gas Payables on the Condensed Consolidated Balance Sheets and is valued at a historical cost of gas of $41.4 million and $45.7 million at June 30, 2007 and December 31, 2006. Due to the method of storage accounting elected by Gulf South, the Partnership does not reflect volumes held by Gulf South on behalf of others on its Condensed Consolidated Balance Sheets. As of June 30, 2007 and December 31, 2006, Gulf South held 49.1 trillion British thermal units (TBtu) and 61.0 TBtu of gas owned by shippers. No gas was loaned by Gulf South to shippers as of June 30, 2007 and December 31, 2006.

Note 3: 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 risk and interest rate risk. These hedge contracts are reported at fair value in accordance with Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended. The effective component of 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. The deferred gains and losses are recognized in the Condensed Consolidated Statements of Income when the hedged anticipated transactions affect earnings.

Certain volumes of gas stored underground are available for sale and subject to commodity price risk. At June 30, 2007 and December 31, 2006, approximately $12.1 million and $14.0 million of gas stored underground at the Gulf South facilities, which the Partnership owns and carries as current Gas stored underground, is exposed to commodity price risk. The Partnership utilizes derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas.

As a result of the approval of Phase II of the Western Kentucky storage expansion project, approximately 4.8 billion cubic feet (Bcf) of gas stored underground with a book value of $11.3 million is available for sale. Approximately 3.0 Bcf of this gas is subject to forward sales agreements under which the ultimate sales price was determined in March 2007, based on the price of New York Mercantile Exchange (NYMEX) natural gas futures. The Partnership entered into derivatives to hedge the price exposure related to the storage gas. The derivatives associated with the volumes subject to forward sales agreements were designated as cash flow hedges during February 2007, concurrent with the designation of the forward sales agreements as normal sales. Prior to the designation, these derivatives were marked to fair value through earnings along with the related forward sales agreements, resulting in a loss of $0.1 million for the first quarter 2007. The derivatives related to the remaining 1.8 Bcf of storage gas were also marked to fair value through earnings resulting in a gain of $1.4 million and a loss of $0.6 million for the three and six months ended June 30, 2007.

In the second quarter 2007, the Partnership entered into natural gas price swaps to hedge exposure to prices associated with the purchase of 2.1 Bcf of natural gas to be used for line pack for the Partnership's Gulf Crossing expansion project and the Southeast expansion project. The derivatives were not designated as hedges in accordance with SFAS No. 133 and were marked to fair value through earnings resulting in a loss of $0.7 million in the second quarter 2007.

With the exception of the storage gas volumes and line pack gas purchases referred to above, the derivatives related to the sale or purchase of natural gas and cash for fuel reimbursement generally qualify for cash flow hedge accounting under SFAS No. 133 and are designated as such. Generally, for gas sales and cash for fuel reimbursement, any gains and losses on the related derivatives would be recognized in Operating Revenues. For the sale of gas related to the Western Kentucky storage expansion project, any gains and losses on the related derivatives would be recognized in Net loss on disposal of operating assets and related contracts. Any gains and losses on the derivatives related to the line pack gas purchases would be recognized in Miscellaneous other income, net.

In August 2006, the Partnership entered into Treasury rate locks with two counterparties each for a notional amount of $100.0 million of principal to hedge the risk attributable to changes in the risk-free component of forward 10-year interest rates through August 1, 2007. The reference rates on the rate locks are 5.00% and 4.96%. Under the terms of the rate locks, the counterparties would pay the Partnership settlement amounts if the 10-year Treasury rate is greater than the reference rates on August 1, 2007. Conversely, the Partnership would pay the counterparties settlement amounts if the 10-year Treasury rate is less than the reference rates. The Treasury rate locks were designated as cash flow hedges in accordance with SFAS No. 133. As of June 30, 2007, the Partnership reported a receivable of $1.6 million, and an increase in Accumulated other comprehensive income in an equal and offsetting amount less ineffectiveness recognized in 2007 of less than $0.1 million, for the fair values of the rate locks.

The fair values of derivatives existing as of June 30, 2007 and December 31, 2006, were included in the following captions in the Condensed Consolidated Balance Sheets (in millions):

	June 30, 2007	December 31, 2006
Prepaid expenses and other current assets	$ 4.3	$ 13.7
Other current liabilities	0.4	5.1
Other Liabilities and Deferred Credits - Other	0.6	-
Accumulated other comprehensive income	4.6	8.5

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 the anticipated transactions are deemed no longer probable to occur, hedge accounting would be terminated and changes in the fair values of the associated derivative financial instruments would be recognized currently in the Condensed Consolidated Statements of Income. Ineffectiveness recorded during the three and six month periods ended June 30, 2007 was $0.1 million favorable and $0.4 million favorable. The Partnership did not record any ineffectiveness during the three and six month periods ending June 30, 2006. The Partnership did not have any cash flow hedges discontinued during the three and six months ended June 30, 2007 and 2006.

Note 4: Income Taxes

The Partnership is not a taxable entity for federal income tax purposes. As such, it does not directly pay federal income tax. The Partnership's taxable income or loss, which may vary substantially from the net income or loss reported in the

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 it does not have access to the information about each partner's tax attributes related to the Partnership. The Partnership's subsidiaries directly incur some income-based state taxes which are presented in Income taxes on the Condensed Consolidated Statements of Income.

Note 5: Commitments and Contingencies

A. Impact of Hurricanes Katrina and Rita

In August and September 2005, Hurricanes Katrina and Rita and related storm activity caused extensive and catastrophic physical damage to the offshore, coastal and inland areas in the Gulf Coast region of the United States. A substantial portion of the Gulf South assets and a smaller portion of the Texas Gas assets are located in the area directly impacted by the hurricanes.

In the fourth quarter 2006, the Partnership recognized a receivable of $4.7 million associated with insurance claims deemed probable of recovery. In 2007, the Partnership received a final cash payment of $6.2 million related to damages incurred during Hurricane Katrina, $4.7 million of which was applied against the receivable and $1.5 million of which was recognized in Gas transportation revenue. Through June 30, 2007, the Partnership has received approximately $12.2 million in insurance proceeds related to the hurricanes and continues to work with the insurance carriers and claims adjusters regarding recovery of its property damage losses associated with Hurricane Rita. During the first quarter 2006, the Partnership accrued additional expenses of $2.1 million, and recognized $2.7 million of insurance proceeds related to Hurricane Katrina, which were received in the fourth quarter 2006. During the second quarter 2006, as a result of a change in estimate primarily related to property retirements, the Partnership reduced the liability accrued for damage incurred during Hurricane Rita by $2.9 million. This decrease resulted in a reduction in overall expense related to the hurricanes of $0.8 million for the six months ended June 30, 2006 on its Condensed Consolidated Statements of Income. The remaining liability for the hurricanes was $0.8 million and $1.0 million as of June 30, 2007 and December 31, 2006.

B. Legal Proceedings

Napoleonville Salt Dome Matter

In December 2003, natural gas leaks were observed near two natural gas storage caverns that were being leased and operated by Gulf South for natural gas storage in Napoleonville, Louisiana. Gulf South commenced remediation efforts immediately and ceased using those storage caverns. Several actions have been filed against Gulf South and other defendants by local residents and businesses as well as the lessor of the property seeking monetary damages. Gulf South continues to vigorously defend each of these actions; however, it is not possible to predict the outcome of this litigation as the cases remain in discovery. Litigation is subject to many uncertainties, and it is possible these actions could be decided unfavorably. Gulf South has settled several of the cases filed against it and may enter into discussions in an attempt to settle other cases if Gulf South believes it is appropriate to do so.

The remediation work related to the incident was completed in November 2006. Gulf South incurred $7.6 million for remediation costs, root cause investigation and legal fees. Gulf South has made demand for reimbursement from its insurance carriers and will continue to pursue recoveries of the costs incurred, including legal expenses. To date the insurance carriers have not taken any definitive coverage positions on all of the issues raised in the various lawsuits. Through June 30, 2007, Gulf South has received $0.8 million of insurance reimbursements for legal expenses and root cause investigation.

The NET Complaint

On June 2, 2007 a complaint was filed by National Energy & Trade, LP (NET) at the Federal Energy Regulatory Commission (FERC) against Texas Gas and Gulf South. In its complaint NET alleges that Texas Gas failed to follow its tariff in awarding capacity, Texas Gas violated the Natural Gas Act in awarding transportation capacity to Gulf South, and Texas Gas and Gulf South engaged in market manipulation in violation of the Energy Policy Act of 2005. Texas Gas and Gulf South have filed a response to this complaint categorically denying each of the allegations and intend to vigorously defend the Partnership against this complaint. Since litigation is subject to many uncertainties it is possible that this action could be decided unfavorably. The Partnership does not believe that this complaint will have a material effect on Partners' Capital, cash flows or earnings.

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 or cash flows.

C. Regulatory and Rate Matters

Expansion Projects

East Texas to Mississippi Expansion. On June 18, 2007 the FERC granted Gulf South the primary authority to construct, own and operate a pipeline expansion consisting of approximately 242 miles of 42-inch pipeline from DeSoto Parish in western Louisiana to near Harrisville, Mississippi and approximately 110,000 horsepower of new compression. The expansion will add approximately 1.7 Bcf per day of new transmission capacity to the Gulf South pipeline system. This project is supported by firm transportation agreements with customers who have contracted, on a long-term basis (with a weighted average term of approximately 7 years), for 1.4 Bcf per day of capacity from Carthage, Texas. Construction of this project has commenced and the Partnership expects this project to be in service during the fourth quarter 2007.

Gulf Crossing Project. The Partnership is pursuing construction of a new interstate pipeline that will begin near Sherman, Texas and proceed to the Perryville, Louisiana area. The project will be owned by Gulf Crossing Pipeline Company LLC (Gulf Crossing), a subsidiary of the Partnership, and will consist of approximately 357 miles of 42-inch pipeline having capacity of up to approximately 1.7 Bcf per day. Additionally, Gulf Crossing will enter into: (i) a lease for up to 1.4 Bcf per day of capacity on the Partnership's Gulf South pipeline system (including capacity on the Southeast Expansion and capacity on a portion of the East Texas to Mississippi Expansion) to make deliveries to an interconnect with Transcontinental Pipe Line Company (Transco) in Choctaw County, Alabama (Transco 85); and (ii) a lease with a third-party intrastate pipeline which will bring certain gas supplies to the Partnership's system. This project is supported by firm transportation agreements with customers who have contracted, on a long-term basis (with a weighted average term of approximately 9.5 years), for 1.1 Bcf per day of capacity and options with certain of these customers for an additional 350 MMcf per day of firm transportation capacity. The certificate application for this project was filed with the FERC on June 19, 2007 and the project is expected to be in service during the fourth quarter 2008. The Partnership continues to engage in negotiations concerning the possible sale of up to a 49.0% equity interest in Gulf Crossing.

Southeast Expansion. The Partnership is pursuing a pipeline expansion extending its Gulf South pipeline system from near Harrisville, Mississippi to an interconnect with Transco 85, which will enhance its ability to deliver gas to the Northeast through other pipeline interconnects. This expansion will consist of approximately 112 miles of 42-inch pipeline having initial capacity of approximately 1.2 Bcf per day, expandable to as much as 2.2 Bcf per day to accommodate volumes expected to come from the Gulf Crossing leased capacity discussed above. In addition, Gulf South has executed a lease with Destin Pipeline Company to access markets in Florida. This project is supported by firm transportation agreements with customers who have contracted, on a long-term basis (with a weighted-average term of 8.7 years), for 660 MMcf per day of capacity as well as the capacity leased to Gulf Crossing discussed above. The certificate application for this project was filed with the FERC in December 2006 and the project is expected to be in service during the first quarter 2008. The FERC issued a draft environmental impact statement for the expansion project on April 13, 2007.

Fayetteville and Greenville Laterals. The Partnership is pursuing the construction of two laterals connected to the Partnership's pipeline system to transport gas from the Fayetteville Shale area in Arkansas to markets directly and indirectly served by the Partnership's existing interstate pipelines. The Fayetteville Lateral, consisting of approximately 165 miles of 36-inch pipeline, has an initial design capacity of approximately 800 MMcf per day. This lateral will originate in Conway County, Arkansas and proceed southeast through the Bald Knob, Arkansas area to an interconnect with Texas Gas' mainline in Coahoma County, Mississippi. The Greenville Lateral, consisting of approximately 95 miles of pipeline with an initial design capacity of 750 MMcf per day, will originate at the Partnership's mainline near Greenville, Mississippi and proceed east to the Kosciusko, Mississippi area. The Greenville Lateral will allow customers to access additional markets, primarily in the Midwest, Northeast and Southeast. Construction of both laterals is supported by a binding precedent agreement with Southwestern Energy Services Company, a wholly-owned subsidiary of Southwestern Energy Company. The certificate application for this project was filed with the FERC on July 11, 2007. The Partnership expects that the first 60 miles of the Fayetteville Lateral will be in service during the third quarter of 2008 and the remainder of the Fayetteville and Greenville Laterals to be in service during the first quarter 2009.

The total cost of the pipeline expansion projects discussed above, before taking into account any potential equity contribution by a third party in Gulf Crossing Pipeline, is estimated to be approximately $3.7 billion which is an increase from the $3.4 billion reported in the first quarter 2007. This increase reflects the expanded pipeline capacity necessary to accommodate additional volumes from assumed capacity options that are considered probable of exercise, contractor penalties incurred as a result of delays in construction and higher labor and materials costs due to the large number of pipeline projects under way throughout the industry. Actual costs may exceed the current estimate due to a variety of factors, including awaiting receipt of regulatory approvals, the timing of which the Partnership cannot control, weather-related costs and further delays in construction which could result in additional contractor and shipper penalties and stand-by costs.

Western Kentucky Storage Expansion. In December 2006, the FERC issued a certificate approving the Phase II storage expansion project which will expand the working gas capacity in the Partnership's western Kentucky storage complex by approximately 9.0 Bcf. This project is supported by binding commitments from customers to contract on a long-term basis for the full additional capacity at Texas Gas' maximum applicable rate. The Partnership expects this project to cost approximately $40.7 million and to be in service by November 2007. In December 2006, Texas Gas commenced an open season related to a potential third expansion of its storage facilities and has signed one precedent agreement for 2.0 Bcf of storage capacity. The certificate application for this project was filed with the FERC on June 25, 2007 seeking up to 8.3 Bcf of new storage capacity if Texas Gas is granted market-based rate authority for the new storage capacity being proposed.

Magnolia Storage Facility. The Partnership has been in the process of developing a salt dome storage cavern near Napoleonville, Louisiana. Operational tests which began in May 2007 and were completed in July have indicated that due to anomalies that could not be corrected, the Partnership will be unable to place the cavern in service as expected. As a result, the Partnership has elected to abandon that cavern and is exploring the possibility of securing a new site on which a new cavern could be developed. In accordance with the requirements of Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* the carrying value of the cavern and related facilities of approximately $45.1 million was tested for recoverability. In the second quarter 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 Condensed Consolidated Statements of Income. The Partnership expects to use the other assets associated with the project, which include pipeline, compressors, base gas and other equipment and facilities, in conjunction with a 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, the Partnership may be required to record an additional impairment charge at the time that determination is made.

Pipeline Integrity

The Office of Pipeline Safety (OPS) has issued a final rule that requires natural gas pipeline operators to develop integrity management programs. Pursuant to the rule, pipelines were required to identify high consequence areas on their systems and develop a written integrity management program providing for a baseline assessment and periodic reassessments to be completed within specified timeframes. The Partnership has complied with these requirements. Its estimated costs to comply with the rule during the initial ten-year baseline period ending in 2012 range from $105.0 to $125.0 million. As of June 30, 2007, the Partnership has invested approximately $10.4 million to develop and implement integrity management programs that allow it to dynamically assess various pipeline risks on an integrated basis. The Partnership has systematically used smart, in-line inspection tools to verify the integrity of certain of its pipelines.

D. 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 the agencies.

As of June 30, 2007 and December 31, 2006, the Partnership had an accrued liability of approximately $17.9 million and $18.4 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 expenditures are expected to occur over approximately the next seven years. The accrual represents management's estimate of the undiscounted future obligations based on evaluations and discussions with counsel and independent consultants and the current facts and circumstances related to these matters. As of June 30, 2007 and December 31, 2006, approximately $3.5 million was recorded in Other current liabilities. As of June 30, 2007 and December 31, 2006, approximately $14.4 million and $14.9 million was recorded in Other Liabilities and Deferred Credits.

On October 20, 2006, Texas Gas received notice from the Environmental Protection Agency (EPA) that Texas Gas is a potentially responsible party under the Comprehensive Environmental Response, Compensation, and Liability Act 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; however, the Partnership does not expect this to have a material effect on its financial condition.

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 Partnership operates two facilities in areas affected by non-attainment requirements for the current ozone standard (eight-hour standard). As of June 30, 2007, the Partnership had incurred costs of approximately $15.6 million for emission control modifications of compression equipment located at facilities required to comply with current CAA provisions, the Amendments and state implementation plans for nitrogen oxide reductions. These costs are being recorded as additions to property, plant and equipment (PPE) as the modifications are added. 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, however the Partnership is unable at this time to estimate with any certainty the cost of any additions that may be required.

The Partnership considers environmental assessment, remediation costs, and costs associated with compliance with environmental standards to be recoverable through base rates, as they are prudent costs incurred in the ordinary course of business and, therefore, no regulatory asset has been recorded to defer these costs. The actual costs incurred will depend on the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA or other governmental authorities and other factors.

E. Commitments for Construction

The Partnership's future capital commitments as of June 30, 2007, for contracts already authorized are expected to approximate the following amounts (in millions):

Less than 1 year	$ 647.6
1-3 years	99.0
4-5 years	-
More than 5 years	-
Total	$ 746.6

The construction work in progress included in Property, plant and equipment, net in the Condensed Consolidated Balance Sheets was $544.2 million and $205.1 million as of June 30, 2007 and December 31, 2006.

Note 6: Net Income per Limited Partner Unit and Cash Distributions

The Partnership calculates net income per limited partner unit in accordance with Emerging Issues Task Force Issue No. 03-6 (EITF No. 03-6), *Participating Securities and the Two-Class Method under FASB Statement No. 128*. In Issue 3 of EITF No. 03-6, the EITF reached a consensus that undistributed earnings for a period should be allocated to a participating security based on the contractual participation rights of the security to share in those earnings as if all of the earnings for the period had been distributed. The Partnership's general partner holds contractual participation rights which are incentive distribution rights in accordance with the partnership agreement as follows:

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
	Target Amount	Common and Subordinated Unitholders	General Partner
Minimum Quarterly Distribution	$0.3500	98%	2%
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%

The amounts reported for net income per limited partner unit on the Condensed Consolidated Statements of Income for the three and six month periods ended June 30, 2007 and 2006, were adjusted to take into account an assumed allocation to the general partner's incentive distribution rights. Payments made on account of the incentive distribution rights are determined in relation to actual declared distributions and not based on the assumed allocation required by EITF No. 03-6. A reconciliation of the limited partners' interest in net income and net income available to limited partners used in computing net income per limited partner unit follows (in thousands, except weighted average units and per unit data):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2007	2006	2007	2006
Limited partners' interest in net income	$ 34,249	$ 31,262	$ 112,672	$ 99,597
Less assumed allocation to incentive distribution rights	(491)	-	3,696	3,503
Net income available to limited partners	$ 34,740	$ 31,262	$ 108,976	$ 96,094
Less assumed allocation to subordinated units	5,635	7,372	32,009	31,378
Net income available to common units	$ 29,105	$ 23,890	$ 76,967	$ 64,716
Weighted average common units	83,156,122	68,256,122	79,576,012	68,256,122
Weighted average subordinated units	33,093,878	33,093,878	33,093,878	33,093,878
Net income per limited partner unit - common units	$ 0.35	$ 0.35	$ 0.97	$ 0.95
Net income per limited partner unit – subordinated units	$ 0.17	$ 0.22	$ 0.97	$ 0.95

Note 7: Financing

In April 2007, the Partnership's revolving credit facility was amended to increase the aggregate commitments from $400.0 million to $700.0 million and to extend the term to June 29, 2012, among other modifications. As of June 30, 2007 and December 31, 2006, no funds were drawn under the facility. Through June 30, 2007, the Partnership had issued letters of credit for $221.5 million to support certain obligations associated with the Fayetteville Shale expansion project which reduced the available capacity under the facility.

In March 2007, the Partnership completed a public offering of 8.0 million of its common units at a price of $36.50 per unit. The Partnership received proceeds of approximately $293.8 million, net of underwriting discounts and offering expenses, and including approximately $6.0 million from the general partner to maintain its 2.0% general partner interest. After the offering, the Partnership has 83.2 million common units issued and outstanding, of which 29.9 million are held by the public. The balance of the common units and all of the subordinated units are held by BPHC.

As of June 30, 2007 and December 31, 2006 the weighted average interest rate of the Partnership's long-term debt was 5.41%. The Partnership was in compliance with all loan covenants at June 30, 2007.

During the three and six months ended June 30, 2007, the Partnership capitalized interest of $4.2 million and $6.3 million. During the three and six months ended June 30, 2006, the Partnership capitalized interest of approximately $0.1 million. In accordance with SFAS No. 71, *Accounting for the Effect of Certain Types of Regulation*, the Partnership's Texas Gas subsidiary capitalizes allowance for funds used during construction (AFUDC), comprised of debt and equity components. The Partnership capitalized $0.7 million and $1.2 million of AFUDC for the three and six months ended June 30, 2007. The Partnership capitalized $0.3 million and $0.6 million of AFUDC for the three and six months ended June 30, 2006.

Note 8: Credit Concentration

Natural gas price volatility has increased dramatically in recent years which has materially increased credit risk related to gas loaned to customers. As of June 30, 2007, the amount of gas loaned out by the Partnership's subsidiaries was approximately 15.0 TBtu and, assuming an average market price during June 2007 of $7.33 per million British thermal units (MMBtu), the market value of gas loaned out at June 30, 2007 would have been approximately $110.0 million. If any significant customer of the Partnership should have credit or financial problems resulting in a delay or failure to repay the gas they owe to it this could have a material adverse effect on the Partnership's financial condition, results of operations and cash flows.

Note 9: Employee Benefits

Substantially all of Texas Gas' employees are covered under a non-contributory, defined benefit pension plan. Additionally, the Texas Gas Supplemental Retirement Plan provides pension benefits for the portion of an eligible employee's pension benefit that becomes subject to compensation limitations under the Internal Revenue Code. Effective in November 2006, the defined benefit retirement plan was closed to new participants and new employees will be provided benefits under a defined contribution money purchase plan. All Gulf South employees are provided retirement benefits under a similar defined contribution money purchase plan. Texas Gas also provides postretirement life insurance and postretirement health care benefits to certain retired employees. The Partnership uses a measurement date of December 31 for its benefits plans.

Early Retirement Incentive Program

In 2006, Texas Gas implemented an early retirement incentive program (ERIP) which was made available to approximately 240 eligible non-executive employees. Retirements under the program were generally effective January 1, 2007. Approximately 100 of the eligible employees elected to participate in the program. In the first quarter 2007, the Partnership recognized a pension settlement charge related to the ERIP of approximately $3.1 million which was recorded in Administrative and general expense. An additional settlement charge of $0.7 million was recorded in the second quarter 2007, to recognize the effects of retirements associated with the ERIP that were initiated during the period.

Components of Net Periodic Benefit Cost

Components of net periodic benefit cost for both the retirement plans and post retirement benefits other than pensions (PBOP) for the three and six months ended June 30, 2007 and 2006 were the following (in thousands):

	Retirement Plans For the Three Months Ended June 30,		PBOP For the Three Months Ended June 30,	
	2007	2006	2007	2006
Service cost	$ 935	$ 1,079	$ 149	$ 464
Interest cost	1,542	1,614	737	1,582
Expected return on plan assets	(1,695)	(1,775)	(1,199)	(1,157)
Amortization of prior service credit	1	-	(1,940)	(647)
Amortization of unrecognized net loss	69	100	36	330
Settlement charge (ERIP)	700	-	-	-
Regulatory asset decrease	-	-	1,354	1,353
Net periodic expense	$ 1,552	$ 1,018	$ (863)	$ 1,925

	Retirement Plans For the Six Months Ended June 30,		PBOP For the Six Months Ended June 30,	
	2007	2006	2007	2006
Service cost	$ 1,865	$ 2,159	$ 304	$ 1,105
Interest cost	3,225	3,229	1,637	3,526
Expected return on plan assets	(3,580)	(3,550)	(2,367)	(2,326)
Amortization of prior service credit	2	1	(3,880)	(647)
Amortization of unrecognized net loss	146	200	334	770
Settlement charge (ERIP)	3,800	-	-	-
Regulatory asset decrease	-	250	2,708	4,619
Net periodic expense	$ 5,458	$ 2,289	$ (1,264)	$ 7,047

The decrease in the regulatory asset for PBOP is due primarily to the amortization of costs incurred in prior years.

Defined Contribution Plans

The Partnership maintains defined contribution plans covering substantially all of its employees. Costs related to these plans were $1.3 million and $2.6 million for the three and six months ended June 30, 2007 and $1.3 million and $2.5 million for the three and six months ended June 30, 2006.

Note 10: Related Parties

Loews provides a variety of corporate services to the Partnership and its subsidiaries under services agreements. Services provided by Loews include, among others, information technology, tax, risk management, internal audit and corporate development services. Loews charged $2.4 million and $6.6 million for the three and six months ended June 30, 2007 and $2.4 million and $6.5 million for the three and six months ended June 30, 2006 to the Partnership based on the actual time spent by Loews personnel performing these services, plus related expenses.

Distributions paid on common and subordinated units held by BPHC and the 2.0% general partner interest and incentive distribution rights held by Boardwalk GP, LP were $75.6 and $47.6 million during the six months ended June 30, 2007 and 2006. In addition, as a result of the public offering of common units in March 2007, the general partner contributed approximately $6.0 million to maintain its general partner interest.

Note 11: Distributions

The Partnership has declared quarterly distributions per unit to unitholders of record, including common and subordinated units and the 2.0% general partner interest held by its general partner as follows:

Record Date	Payable Date	Distribution per Unit
August 6, 2007	August 13, 2007	0.44
May 7, 2007	May 14, 2007	0.43
February 20, 2007	February 27, 2007	0.415
October 30, 2006	November 6, 2006	0.40
August 11, 2006	August 18, 2006	0.38
May 12, 2006	May 19, 2006	0.36
February 16, 2006	February 23, 2006	0.179*

*Distribution represented a prorated portion of the $0.35 per unit “minimum quarterly distribution” (as defined in the Partnership’s partnership agreement) for the period November 15, 2005 through December 31, 2005.

The Partnership also pays cash distributions to its general partner on account of its incentive distribution rights with respect to that portion of a quarterly distribution in excess of $0.4025 per unit. These payments were $0.7 million for the six months ended June 30, 2007 and will be $0.7 million in the third quarter 2007 based on the declared distribution.

Note 12: Accumulated Other Comprehensive Income

The following table shows the components of Accumulated other comprehensive income at June 30, 2007 and December 31, 2006 (in thousands):

	As of June 30, 2007	As of December 31, 2006
Gain on cash flow hedges	$ 4,619	$ 8,309
Deferred components of net periodic benefit cost	14,779	14,803
Total Accumulated other comprehensive income	$ 19,398	$ 23,112

Note 13: Guarantee of Securities of Subsidiaries

The Partnership has no independent assets or operations other than its investment in its subsidiaries. The Partnership’s operating subsidiaries have issued securities which have all been fully and unconditionally guaranteed by the Partnership. The Partnership does have separate partners’ capital including publicly traded limited partner common units.

The Partnership's subsidiaries have no significant restrictions on their ability to pay distributions or loans to the Partnership and have no restricted assets at June 30, 2007.

Note 14: Recently Issued Accounting Pronouncements

SFAS No. 157

On September 15, 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, *Fair Value Measurements*. Fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. The standard clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In support of this principle, the standard establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity's own data. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. The Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The effective date for the Partnership is January 1, 2008. The Partnership is currently evaluating the impact, if any, that SFAS No. 157 would have on its financial condition, results of operations or cash flows.

SFAS No. 159

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities- including an amendment of SFAS No. 115.* SFAS No. 159 allows companies to elect to measure financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been chosen are reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. The effective date for the Partnership is January 1, 2008. The Partnership is currently evaluating the impact, if any, of adopting SFAS No. 159 on its financial condition, results of operations or cash flows.

Item 2. 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 accompanying interim condensed consolidated financial statements and related notes, included elsewhere in this report and prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) and our consolidated financial statements, related notes, management's discussion and analysis of financial condition and results of operations and Risk Factors included in our Annual Report on Form 10-K for the year ended December 31, 2006.

We are a Delaware limited partnership formed to own and operate the business conducted by Boardwalk Pipelines, LP (Boardwalk Pipelines) and its subsidiaries, Gulf South Pipeline Company, LP (Gulf South) and Texas Gas Transmission, LLC (Texas Gas) (together, the operating subsidiaries). We own and operate pipeline systems in the Gulf Coast states of Texas, Louisiana, Mississippi, Alabama, and Florida and which extend northward through Arkansas to the Midwestern states of Tennessee, Kentucky, Illinois, Indiana, and Ohio.

Results of Operations – Business Overview

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. Transportation rates are subject to maximum tariff rates established by the Federal Energy Regulatory Commission (FERC), although many services are provided at a rate lower than the maximum tariff rates due to competition in the marketplace. Our Gulf South subsidiary is authorized to charge market-based rates for its firm and interruptible storage services.

We are not in the business of buying and selling natural gas other than for system management and operational purposes, but changes in the price of natural gas can affect the overall supply and demand of natural gas which in turn does affect our results of operations. We deliver gas to a broad mix of customers including local distribution companies, municipalities, interstate and intrastate pipelines, direct industrial users, electric power generation plants, marketers and producers. In addition to serving directly connected markets, our pipeline systems have indirect market access to the northeastern and southeastern United States through interconnections with unaffiliated pipelines.

Under firm transportation agreements, customers generally pay a fixed "demand" or "capacity reservation" charge to reserve pipeline capacity at certain receipt and delivery points, plus a commodity and fuel charge paid on the volume of gas actually transported. Firm storage customers reserve a specific amount of storage capacity and injection and withdrawal capability and generally pay a capacity reservation charge based on the amount of capacity being reserved plus an injection and/or withdrawal fee. Capacity reservation revenues derived from a firm service contract (including no-notice storage service) are generally consistent during the contract term, but can be higher in winter peak periods, especially related to no-notice storage agreements, than in off-peak periods. The seasonal effect is also impacted by increased revenues generated from usage during the winter peak periods.

Interruptible transportation and storage services are typically short-term in nature and are generally used by customers that do not require the certainty of delivery that is provided with firm services. Customers pay for interruptible services when the service is used.

Revenues for our parking and lending (PAL) services and certain of our storage services for which we are authorized to charge market-based rates are affected by period-to-period natural gas price spreads (for example, summer to winter). In recent periods, these price spreads have been wider and more volatile than in previous years, resulting in significant increases in parking and lending and storage revenues. We are uncertain if these recent favorable trends in period-to-period natural gas price spreads will continue. A reversal of this trend could result in lower revenues and profits from these services in future periods.

Operating expenses typically do not vary significantly based upon the amount of gas transported with the exception of gas consumed by Gulf South's compressor stations. Gulf South's fuel recoveries are included as part of transportation revenues.

Results of Operations for the Three Months Ended June 30, 2007 and 2006

Our net income for the second quarter 2007 increased $3.5 million or 11.1% from the comparable 2006 period. The primary drivers for the increase were higher revenues from strong demand for firm transportation services, pipeline system expansion and a continued strong environment for PAL and storage services resulting in higher reservation rates. The increased revenues were partly offset by a $14.7 million impairment charge associated with a portion of our Magnolia storage project and slightly higher operating expenses.

Operating revenues for the second quarter 2007 increased $21.8 million, or 16.9%, to $150.5 million, compared to $128.7 million for the second quarter 2006 primarily due to:

- $7.9 million increase in transportation fees due to higher reservation rates, including $2.5 million from new contracts associated with the Carthage, Texas to Keatchie, Louisiana pipeline expansion which was placed in service at the end of 2006;
- $7.9 million increase in fuel revenues from other system volumes and higher realized prices including hedging activity; and
- $6.7 million increase in PAL and storage revenues mainly due to gas parked by customers during summer and fall 2006 for withdrawal during summer 2007.

Operating expenses for the second quarter 2007 increased $23.4 million, or 28.3%, to $106.2 million, compared to $82.8 million for the second quarter 2006 primarily due to:

- $14.7 million loss due to impairment related to the Magnolia storage facility in the 2007 period;
- $4.1 million increase in fuel costs primarily due to an increase in gas usage;
- $2.9 million increase primarily due to a favorable hurricane accrual adjustment made in the 2006 period;
- $2.7 million increase in operation and maintenance expenses due to engine overhauls, remediation and inline inspections at certain locations;
- $1.7 million increase in employee compensation related to long-term incentives; and
- $1.5 million increase in depreciation and amortization resulting primarily from increased property, plant and equipment.

These increases were partly offset by:

- a $2.8 million decline in post retirement benefits other than pensions costs primarily as a result of plan changes implemented in the second half 2006.

Total other deductions for the second quarter 2007 declined by $5.0 million, or 36.5%, to $8.7 million, compared to $13.7 million for the second quarter 2006, primarily due to an increase in interest income of $5.3 million as a result of higher levels of invested cash.

Results of Operations for the Six Months Ended June 30, 2007 and 2006

Our net income for the first six months of 2007 increased $14.1 million or 13.9% from the comparable 2006 period. The primary drivers for the increase were higher revenues from increased utilization and strong demand for firm transportation services, pipeline system expansion and a continued strong environment for PAL and storage services resulting in higher reservation rates. The higher revenues were partly offset by a $14.7 million impairment charge associated with a portion of our Magnolia storage project and slightly higher operating expenses.

Operating revenues for the six months ended June 30, 2007 increased $35.6 million, or 11.7%, to $338.7 million, compared to $303.1 million for the six months ended June 30, 2006 primarily due to:

- $13.9 million increase in fuel revenues due to an increase in other system volumes and higher realized gas prices including hedging activity;
- $13.8 million increase in transportation fees due to higher reservation rates, including $4.2 million from new contracts associated with the Carthage, Texas to Keatchie, Louisiana pipeline expansion; and
- $9.6 million increase in PAL and storage services mainly due to gas parked by customers during summer and fall 2006 for withdrawal during summer 2007.

These increases were partly offset by:

- $1.6 million due to a decrease in the amortization of acquired executory contracts.

Operating expenses for the six months ended June 30, 2007 increased $29.4 million, or 17.0%, to $202.0 million, compared to $172.6 million for the six months ended June 30, 2006 primarily due to:

- $14.7 million loss due to impairment related to the Magnolia storage facility during 2007;
- $3.6 million increase in fuel costs primarily due to an increase in gas usage;
- $3.5 million increase primarily due to favorable items in the 2006 period related to hurricane recoveries recognized and an adjustment related to the hurricane accrual;
- $3.2 million increase in property and other taxes primarily as a result of a reversal of a franchise tax accrual in the 2006 period;
- $3.0 million increase in operation and maintenance expenses due to engine overhauls, remediation and inline inspections at certain locations;
- $2.7 million increase in depreciation and amortization resulting from increased property, plant and equipment;
- $2.0 million increase in employee compensation related to long-term incentives; and
- $1.9 million loss on mark-to-market adjustments associated with hedges on line pack for pipeline expansion projects and storage gas sales.

These increases were partly offset by:

- $5.1 million net decrease in pension and postretirement benefits expenses, mainly comprised of an $8.3 million reduction in postretirement benefits as a result of plan changes implemented in the second half 2006, partly offset by a $3.8 million pension settlement charge related to an early retirement incentive program (ERIP).

Total other deductions for the six months ended June 30, 2007 declined by $8.0 million, or 28.0%, to $20.6 million, compared to $28.6 million for the six months ended June 30, 2006. The decline is primarily due to an increase in interest income of $9.3 million as a result of higher levels of invested cash.

Capital Expenditures

Capital expenditures for the six months ended June 30, 2007 and 2006 were $380.1 million and $55.2 million. For the year ending December 31, 2007, we expect to make capital expenditures of approximately $1.5 billion, of which we expect approximately $1.47 billion to be for the expansion projects discussed below and approximately $60.0 million to be for maintenance capital. The amount of expansion capital we expend in 2007 could vary significantly depending on the progress made with these projects, the number and types of other capital projects we decide to pursue, the timing of any of those projects and numerous other factors beyond our control.

We expect to fund our expansion capital expenditures for 2007 and beyond with proceeds from sales of our debt and equity securities, borrowings under our revolving credit facility and operating cash flows, though we have not made any determination with regard to such financing. We expect to fund our maintenance capital expenditures from operating cash flows.

We are currently engaged in the following expansion projects:

- *East Texas to Mississippi Expansion.* On June 18, 2007 the FERC granted Gulf South the primary authority to construct, own and operate a pipeline expansion consisting of approximately 242 miles of 42-inch pipeline from DeSoto Parish in western Louisiana to near Harrisville, Mississippi and approximately 110,000 horsepower of new compression. The expansion will add approximately 1.7 Bcf per day of new transmission capacity to the Gulf South pipeline system. This project is supported by firm transportation agreements with customers who have contracted, on a long-term basis (with a weighted average term of approximately 7 years), for 1.4 Bcf per day of capacity from Carthage, Texas. Construction of this project has commenced and we expect this project to be in service during the fourth quarter 2007.

- *Gulf Crossing Project.* We are pursuing construction of a new interstate pipeline that will begin near Sherman, Texas and proceed to the Perryville, Louisiana area. The project will be owned by Gulf Crossing Pipeline Company LLC (Gulf Crossing), a subsidiary of ours, and will consist of approximately 357 miles of 42-inch pipeline having capacity of up to approximately 1.7 Bcf per day. Additionally, Gulf Crossing will enter into: (i) a lease for up to 1.4 Bcf per day of capacity on our Gulf South pipeline system (including capacity on the Southeast Expansion and capacity on a portion of the East Texas to Mississippi Expansion) to make deliveries to an interconnect with Transcontinental Pipe Line Company (Transco) in Choctaw County, Alabama (Transco 85); and (ii) a lease with a third-party intrastate pipeline which will bring certain gas supplies to our system. This project is supported by firm transportation agreements with customers who have contracted, on a long-term basis (with a weighted average term of approximately 9.5 years), for 1.1 Bcf per day of capacity and options with certain of these customers for an additional 350 MMcf per day of firm transportation capacity. The certificate application for this project was filed with the FERC on June 19, 2007 and the project is expected to be in service during the fourth quarter 2008. We continue to engage in negotiations concerning the possible sale of up to a 49.0% equity interest in Gulf Crossing.

- *Southeast Expansion*. We are pursuing a pipeline expansion extending our Gulf South pipeline system from near Harrisville, Mississippi to an interconnect with Transco 85, which will enhance our ability to deliver gas to the Northeast through other pipeline interconnects. This expansion will consist of approximately 112 miles of 42-inch pipeline having initial capacity of approximately 1.2 Bcf per day, expandable to as much as 2.2 Bcf per day to accommodate volumes expected to come from the Gulf Crossing leased capacity discussed above. In addition, Gulf South has executed a lease with Destin Pipeline Company to access markets in Florida. This project is supported by firm transportation agreements with customers who have contracted, on a long-term basis (with a weighted-average term of 8.7 years), for 660 MMcf per day of capacity as well as the capacity leased to Gulf Crossing discussed above. The certificate application for this project was filed with the FERC in December 2006 and the project is expected to be in service during the first quarter 2008. The FERC issued a draft environmental impact statement for the expansion project on April 13, 2007.

- *Fayetteville and Greenville Laterals*. We are pursuing the construction of two laterals connected to our pipeline system to transport gas from the Fayetteville Shale area in Arkansas to markets directly and indirectly served by our existing interstate pipelines. The Fayetteville Lateral, consisting of approximately 165 miles of 36-inch pipeline, has an initial design capacity of approximately 800 MMcf per day. This lateral will originate in Conway County, Arkansas and proceed southeast through the Bald Knob, Arkansas area to an interconnect with Texas Gas' mainline in Coahoma County, Mississippi. The Greenville Lateral, consisting of approximately 95 miles of pipeline with an initial design capacity of 750 MMcf per day, will originate at our mainline near Greenville, Mississippi and proceed east to the Kosciusko, Mississippi area. The Greenville Lateral will allow customers to access additional markets, primarily in the Midwest, Northeast and Southeast. Construction of both laterals is supported by a binding precedent agreement with Southwestern Energy Services Company, a wholly-owned subsidiary of Southwestern Energy Company. The certificate application for this project was filed with the FERC on July 11, 2007. We expect that the first 60 miles of the Fayetteville Lateral will be in service during the third quarter of 2008 and the remainder of the Fayetteville and Greenville Laterals to be in service during the first quarter 2009.

The total cost of the pipeline expansion projects discussed above, before taking into account any potential equity contribution by a third party in Gulf Crossing Pipeline, is estimated to be approximately $3.7 billion which is an increase from the $3.4 billion reported in the first quarter 2007. This increase reflects the expanded pipeline capacity necessary to accommodate additional volumes from assumed capacity options that are considered probable of exercise, contractor penalties incurred as a result of delays in construction and higher labor and materials costs due to the large number of pipeline projects under way throughout the industry. Actual costs may exceed the current estimate due to a variety of factors, including awaiting receipt of regulatory approvals, the timing of which we cannot control, weather-related costs and further delays in construction which could result in additional contractor and shipper penalties and stand-by costs.

- *Western Kentucky Storage Expansion.* In December 2006, the FERC issued a certificate approving the Phase II storage expansion project which will expand the working gas capacity in our western Kentucky storage complex by approximately 9.0 Bcf. This project is supported by binding commitments from customers to contract on a long-term basis for the full additional capacity at Texas Gas' maximum applicable rate. We expect this project to cost approximately $40.7 million and to be in service by November 2007. In December 2006, Texas Gas commenced an open season related to a potential third expansion of our storage facilities and has signed one precedent agreement for 2.0 Bcf of storage capacity. The certificate application for this project was filed with the FERC on June 25, 2007 seeking up to 8.3 Bcf of new storage capacity if Texas Gas is granted market-based rate authority for the new storage capacity being proposed.

- *Magnolia Storage Facility.* We have been in the process of developing a salt dome storage cavern near Napoleonville, Louisiana. Operational tests which began in May 2007 and were completed in July have indicated that due to anomalies that could not be corrected, we will be unable to place the cavern in service as expected. As a result, we have elected to abandon that cavern and are exploring the possibility of securing a new site on which a new cavern could be developed. In accordance with the requirements of Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* the carrying value of the cavern and related facilities of approximately $45.1 million was tested for recoverability. In the second quarter 2007 we recognized an impairment charge to earnings of approximately $14.7 million, representing the carrying value of the cavern. We expect to use the other assets associated with the project, which include pipeline, compressors, base gas and other equipment and facilities, in conjunction with a 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, we may be required to record an additional impairment charge at the time that determination is made.

Distributions

Note 11 in Item 1 of this Report contains information regarding our distributions.

Liquidity and Capital Resources

We are a limited partnership holding company and derive all of our operating cash flow from our operating subsidiaries. Boardwalk Pipelines uses cash provided from its subsidiaries and, as needed, borrowings under its revolving credit facility to service its indebtedness and make distributions or advances to us to fund our distributions to unitholders and our general partner.

In April 2007, our revolving credit facility was amended to increase the aggregate commitments from $400.0 million to $700.0 million and to extend the term to June 29, 2012, among other modifications. As of June 30, 2007 and December 31, 2006, no funds were drawn under the facility. During April 2007, we issued letters of credit for $221.5 million to support certain obligations associated with the Fayetteville Shale expansion project which reduced the available capacity under the facility.

In March 2007, we completed a public offering of 8.0 million of our common units. We received proceeds of approximately $293.8 million, net of underwriting discounts and offering expenses, and including approximately $6.0 million from our general partner to maintain its 2.0% general partner interest. The proceeds will primarily be used to fund capital expenditures associated with the expansion projects. After the offering, we have 83.2 million common units issued and outstanding, of which 29.9 million are held by the public. The balance of the common units plus all of the subordinated units are held by Boardwalk Pipelines Holding Corp. (BPHC).

Changes in cash flow from operating activities

Net cash provided by operating activities increased $35.2 million, or 25.8%, to $171.7 million for the six months ended June 30, 2007, compared to $136.5 million for the comparable 2006 period, primarily due to:

- $35.8 million improvement in net income, excluding non-cash items such as depreciation and amortization and the Magnolia impairment charge was primarily driven by an increase in revenues partly offset by slightly higher operating expenses; and
- $14.6 million increase in cash due to gas purchases made in 2006 to repay gas imbalances with shippers and other interstate pipelines.

These increases were partly offset by:

- $25.6 million reduction in cash due to recognition of deferred income related to PAL revenues.

Changes in cash flow from investing activities

Net cash used in investing activities increased $332.5 million to $379.2 million for the six months ended June 30, 2007, compared to $46.7 million for the comparable 2006 period, primarily due to a $324.9 million increase in capital expenditures mainly for our expansion projects.

Changes in cash flow from financing activities

Net cash provided by (used in) financing activities increased $294.1 million to $196.3 million for the six months ended June 30, 2007, compared to a use of $97.8 million for the comparable 2006 period, primarily due to $293.8 million in net equity offering proceeds from the sale of 8,000,000 units and related general partner capital contribution in March 2007.

Contractual Obligations

The table below is updated for significant changes in capital commitments from those included in the 2006 Annual Report on Form 10-K by period (in millions):

	Payments due by Period				
	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Capital commitments	$ 746.6	$ 647.6	$ 99.0	$ -	$ -

The capital commitments for construction were primarily related to the pipeline expansion projects. For further discussion of the expansion projects please read Note 5C *Expansion Projects* in the Notes to condensed consolidated financial statements included in Item 1.

Off Balance Sheet Arrangements

At June 30, 2007, 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 and Estimates

Certain amounts included in or affecting our condensed 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 at the date of 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 period in which the facts that give rise to the revision become known.

At June 30, 2007, the carrying value of our Magnolia storage expansion project was tested for impairment. As a result of the impairment test, we recognized a $14.7 million impairment charge representing the carrying value of the cavern. In determining that the fair value of the cavern was zero, estimates and assumptions were made regarding the cash flows associated with the cavern disposal through sale or abandonment. Although we believe that alternative uses for the cavern may be possible in the hands of a third-party, and will pursue the sale of the cavern, we believe that the probability of a sale is unlikely. In assessing the carrying value of the other associated facilities which include pipeline, compressors, base gas and other equipment and facilities, we assumed that the facilities would be used in conjunction with a replacement storage cavern to be developed. Our expected cash flows related to the other facilities include the cost of developing a new cavern and revenues from the sale of storage services to third-parties over the useful life of the asset. If storage spreads were to compress appreciably or significant difficulties were to arise in the development of the cavern, the actual cash flows could differ materially from the expected cash flows used in assessing the carrying value of the facilities. If it is determined in the future that the assets cannot be used in conjunction with a new cavern, we may be required to record an additional impairment charge at the time that determination is made.

During the six months ended June 30, 2007, there were no significant changes to our critical accounting policies' judgments or estimates disclosed in our Annual Report on Form 10-K for the year ended December 31, 2006.

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" statements. 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 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, which may be provided by management, 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:

- We may not complete projects, including growth or expansion projects, that we commence, or we may complete projects on materially different terms or timing than anticipated and we may not be able to achieve the intended benefits of any such project, if completed.

- The successful completion, timing, cost, scope and future financial performance of our expansion projects could differ materially from our expectations due to availability of contractors, weather, untimely regulatory approvals or denied applications, delayed approvals by regulatory bodies, land owner opposition, the lack of adequate materials, labor difficulties, difficulties we may encounter with partners or potential partners, expansion cost higher than anticipated and numerous other factors beyond our control.

- We may not complete any future debt or equity financing transaction, including any sale of an equity interest in Gulf Crossing Pipeline.

- The gas transmission and storage operations of our subsidiaries are subject to rate-making policies and actions by the FERC or customers that could have an adverse impact on the rates we charge and the revenues we collect may not cover our full cost of operating our pipelines and a reasonable return.

- We are subject to laws and regulations relating to the environment and pipeline operations which may expose us to significant costs, liabilities and loss of revenues. Any changes in such regulations or their application could negatively affect our business, financial condition and results of operations.

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

- The cost of insuring our assets may increase dramatically.

- Because of the natural decline in gas production from existing wells, our success depends on our ability to obtain access to new sources of natural gas, which is dependent on factors beyond our control. Any decrease in supplies of natural gas in our supply areas could adversely affect our business, financial condition and results of operations.

- Successful development of LNG import terminals in the eastern or northeastern United States could reduce the demand for our services.

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

- Significant changes in natural gas prices could affect supply and demand, reducing system throughput and adversely affecting our revenues.

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 3. Quantitative and Qualitative Disclosures About Market Risk

Our long-term debt is subject to interest rate risk. Total long-term debt at June 30, 2007, had a carrying value of $1.4 billion and a fair value of $1.3 billion. The weighted-average interest rate of our long-term debt was 5.41% at June 30, 2007.

In August 2006, we entered into Treasury rate locks with two counterparties each for a notional amount of $100.0 million of principal to hedge the risk attributable to changes in the risk-free component of forward 10-year interest rates through August 1, 2007. The reference rates on the rate locks are 5.00% and 4.96%. Under the terms of the rate locks, the counterparties would pay us settlement amounts if the 10-year Treasury rate is greater than the reference rates at October 1, 2007. Conversely, we would pay the counterparties settlement amounts if the 10-year Treasury rate is less than the reference rates. A 10 basis point increase in the 10-year Treasury rate would result in a $1.6 million favorable change in the value of the rate locks. Conversely, a 10 basis point decrease in the 10-year Treasury rate would result in a $1.6 million unfavorable change in the value of the rate locks. The Treasury rate locks were designated as cash flow hedges in accordance with SFAS No. 133. As of June 30, 2007, we reported a receivable of $1.6 million, and an increase in Accumulated other comprehensive income in an equal and offsetting amount less ineffectiveness recognized in 2007 of less than $0.1 million, for the fair values of the rate locks.

Certain volumes of our gas stored underground are available for sale and subject to commodity price risk. At June 30, 2007 and December 31, 2006, approximately $12.1 million and $14.0 million of our gas stored underground, which we own and carry as current Gas stored underground, is exposed to commodity price risk. Our operating subsidiaries utilize derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas and also for cash received for fuel reimbursement.

As a result of the Texas Gas Western Kentucky storage expansion project, approximately 4.8 Bcf of gas stored underground with a book value of $11.3 million is available for sale. Approximately 3.0 Bcf of this gas is subject to forward sales agreements under which the ultimate sales price was determined in March 2007, based on the price of New York Mercantile Exchange (NYMEX) natural gas futures. Texas Gas entered into derivatives to hedge the price exposure related to the storage gas. The derivatives associated with the volumes subject to forward sales agreements were designated as cash flow hedges during February 2007. Prior to the designation, these derivatives were marked to fair value through earnings along with the related forward sales agreements, resulting in a loss of $0.1 million in the six months ended June 30, 2007. The derivatives related to the remaining 1.8 Bcf of storage gas were also marked to fair value through earnings resulting in a gain of $1.4 million and a loss of $0.6 million in the three and six months ended June 30, 2007.

In the second quarter 2007, we entered into natural gas price swaps to hedge exposure to prices associated with the purchase of 2.1 Bcf of natural gas to be used for line pack for our Gulf Crossing expansion project and the Southeast expansion project, approximately 1.6 Bcf of which remained outstanding at June 30, 2007. The derivatives were not designated as hedges in accordance with SFAS No. 133 and were marked to fair value through earnings resulting in a loss of $0.7 million in the second quarter 2007. Changes in the fair value of the derivatives will be recognized in earnings each quarter until settlement. The changes in the fair value of the gas purchased for line pack will not be recognized in earnings each quarter. When the gas is purchased, the ultimate cost will be recorded to Property, Plant and Equipment along with the other capital components of the projects and recognized in earnings as the property is depreciated. A $1.00 increase in the price of NYMEX natural gas futures, would result in the recognition of a $1.6 million gain in earnings. Conversely, a $1.00 decrease would result in the recognition of a $1.6 million loss.

With the exception of the storage gas volumes and line pack gas purchases referred to above, the derivatives related to the sale or purchase of natural gas and cash for fuel reimbursement generally qualify for cash flow hedge accounting under SFAS No. 133 and are designated as such. 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. The deferred gains and losses are recognized in the Condensed Consolidated Statements of Income when the hedged anticipated purchases or sales affect earnings.

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 we measure 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 the anticipated transactions are deemed no longer probable to occur, hedge accounting would be terminated and changes in the fair values of the associated derivative financial instruments would be recognized currently in the Condensed Consolidated Statements of Income.

We are exposed to credit risk relating 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, as well as volumes owed by customers for imbalances or gas lent by us to them, generally under PAL and no-notice service (NNS). We maintain credit policies intended to minimize credit risk and actively monitor these policies. Natural gas price volatility has increased dramatically in recent years, which has materially increased credit risk related to gas loaned to customers. As of June 30, 2007, the amount of gas loaned out by our subsidiaries was approximately 15.0 trillion British thermal units (TBtu) and, assuming an average market price during June 2007 of $7.33 per million British thermal units (MMBtu), the market value of gas loaned out at June 30, 2007 would have been approximately $110.0 million. As of December 31, 2006, the amount of gas loaned out by our subsidiaries was approximately 15.1 TBtu and, assuming an average market price during December 2006 of $6.81 per MMBtu, the market value of gas loaned out at December 31, 2006 would have been approximately $102.8 million. 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 financial condition, results of operations and cash flows.

As of June 30, 2007, our cash equivalents were invested primarily in money market investments. Due to the short-term nature and type of our investments, a hypothetical 10% increase in interest rates would not have a material effect on the fair market value of our portfolio. Since we have the ability to liquidate this portfolio, we do not expect our Condensed Consolidated Statements of Income or Cash Flows to be materially affected by the effect of a sudden change in market interest rates on our investment portfolio.

Item 4. Controls and Procedures

We maintain a system of disclosure controls and procedures which are designed to ensure that information required to be disclosed in reports filed or submitted under the federal securities laws, including this report, is recorded, processed, summarized and reported on a timely basis. These disclosure controls and procedures are designed to ensure that information required to be disclosed under the federal securities laws is accumulated and communicated to management on a timely basis to allow assessment of required disclosures.

Our principal executive officer and principal financial officer have conducted an evaluation of the disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, the principal executive officer and principal financial officer have each concluded that the disclosure controls and procedures are effective.

There was no change in our internal control over financial reporting identified in connection with the foregoing evaluation that occurred during the six months ended June 30, 2007, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of certain of our current legal proceedings, please read Note 5 of the Notes to condensed consolidated financial statements in Item 1 of this Report.

Item 1 A. Risk Factors

The following discussion supplements the Risk Factors in Item 1A "Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2006.

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, 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.

Our natural gas transportation, gathering and storage operations are subject to FERC rate-making policies that could have an adverse impact on our ability to establish rates that would allow us to recover the full cost of operating our pipelines including a reasonable return and our ability to service our debt.

Action by the FERC on currently pending matters as well as matters arising in the future could adversely affect our ability to establish rates, or to charge rates that would cover future increases in our costs, or even to continue to collect rates that cover current costs, including a reasonable return. We cannot make assurances that we will 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 Texas Gas or Gulf South could have a material adverse effect on our business, financial condition and results of operations that could have an adverse impact on our ability to service our debt.

On July 20, 2004, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued its opinion in *BP West Coast Products, LLC v. FERC (BP West Coast)* and vacated the portion of the FERC's decision applying the FERC's *Lakehead* policy to determine an allowance for income taxes in the regulated cost of service. In its *Lakehead* decision, the FERC allowed an oil pipeline limited partnership to include in its cost of service an income tax allowance to the extent that its unitholders were corporations subject to income tax. The D.C. Circuit emphasized that a regulated pipeline's cost of service should include only "appropriate cost[s]" and compared income taxes paid by owners of equity interests in a pipeline to the costs of bookkeeping paid by such owners, indicating the court's belief that such costs paid by an entity other than the regulated entity would not be recoverable in the rates of the pipeline. In May and June 2005, the FERC issued a statement of general policy and an order on remand of *BP West Coast*, respectively, in which the FERC stated it will permit pipelines to include in cost-of-service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the new policy is generally favorable for pipelines that are organized as pass-through entities, it still entails risk due to the case-by-case review requirement. On December 16, 2005, the FERC issued a case-specific review of the income tax allowance issue in the *SFPP, L.P.* proceeding. The FERC ruled favorably to SFPP, L.P. on all income tax issues and set forth guidelines regarding the type of evidence necessary for the pipeline to determine its income tax allowance. The FERC's *BP West Coast* remand decision, the new tax allowance policy, and the December 16, 2005 order were appealed to the D.C. Circuit. The D.C. Circuit issued an order on May 29, 2007, in which it denied these appeals and fully upheld FERC's new tax allowance policy and the application of that policy in the December 16, 2005 order. We have no way of knowing whether any party will seek rehearing or appeal of the D.C. Circuit's decision. However, it is possible that a party could request rehearing of the decision and/or petition for writ of certiorari to the United States Supreme Court. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC's treatment of income tax allowances in cost of service. If the FERC were to change its tax allowance policies in the future, or if current policy was reversed or changed on appeal by a court, such changes could materially and adversely impact the rates we are permitted to charge as future rates are approved for our interstate transportation services.

If Texas Gas or Gulf South were to file a rate case or if we were to be required to defend our rates, we would be required to establish pursuant to the new policy statement that the inclusion of an income tax allowance in our cost of service was just and reasonable. To establish that our tax allowance is just and reasonable, the Partnership's general partner may elect to require owners of the Partnership's units to recertify their status as being subject to United States federal income taxation on the income generated by Texas Gas or Gulf South. We can provide no assurance that the certification and re-certification procedures provided in the Partnership's partnership agreement will be sufficient to establish that its unitholders, or its unitholders' owners, are subject to United States federal income taxation on the income generated by us. If we are unable to establish that the master partnership's unitholders, or its unitholders' owners, are subject to United States federal income taxation on the income generated by us, the FERC could disallow a substantial portion of Texas Gas' or Gulf South's income tax allowance. If the FERC were to disallow a substantial portion of Texas Gas' or Gulf South's income tax allowance, it is likely that the level of maximum lawful rates could decrease from current levels.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

On March 5, 2007, our general partner purchased 1,500 of our common units in the open market at a price of $36.67 per unit. These units were granted to our independent directors on March 5, 2007 as part of their director compensation.

Item 6. Exhibits

Exhibit Designation	Nature of Exhibit
31.1*	Certification of Rolf A. Gafvert, Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Jamie L. Buskill, Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
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.

* Filed herewith

SIGNATURES

Pursuant to the requirements 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: July 31, 2007

By: *_/s/ Jamie L. Buskill_*
Jamie L. Buskill
Chief Financial Officer

EXHIBIT 31.1

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Rolf A. Gafvert, certify that:

1) I have reviewed this report on Form 10-Q 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 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 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: July 31, 2007

/s/ Rolf A. Gafvert
Rolf A. Gafvert
Chief Executive Officer
(principal executive officer)

EXHIBIT 31.2

CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Jamie L. Buskill, certify that:

1) I have reviewed this report on Form 10-Q 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 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 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: July 31, 2007

/s/ Jamie L. Buskill
Jamie L. Buskill
Chief Financial Officer
(principal financial officer)

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 quarterly report on Form 10-Q for the period ended June 30, 2007, (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.

July 31, 2007

/s/ Rolf A. Gafvert
Rolf A. Gafvert
Chief Executive Officer
(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 quarterly report on Form 10-Q for the period ended June 30, 2007, (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.

July 31, 2007

/s/ Jamie L. Buskill
Jamie L. Buskill
Chief Financial Officer
(principal financial officer)