Boardwalk Pipeline Partners, LP
Form 10-Q
October 30, 2007

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

FORM 10-Q

xQUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2007

OR

oTRANSITION 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 x Noo

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 x Accelerated filer o Non-accelerated filer o

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

As of October 19, 2007, the registrant had 83,156,122 common units outstanding and 33,093,878 subordinated units outstanding.

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BOARDWALK PIPELINE PARTNERS, LP

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

ASSETS	September 30, 2007	December 31, 2006
Current Assets:		
Cash and cash equivalents	$ 45,161	$ 399,032
Short-term investments	540,000	-
Receivables:		
Trade, net	40,543	54,082
Other	12,349	12,759
Gas Receivables:		
Transportation and exchange	8,345	9,115
Storage	653	11,704
Inventories	14,315	14,110
Costs recoverable from customers	6,313	11,236
Gas stored underground	14,252	14,001
Prepaid expenses and other current assets	13,773	22,117
Total current assets	695,704	548,156
Property, Plant and Equipment:		
Natural gas transmission plant	2,752,860	1,997,922
Other natural gas plant	233,031	213,926
	2,985,891	2,211,848
Less—Accumulated depreciation and amortization	243,990	187,412
Property, plant and equipment, net	2,741,901	2,024,436
Other Assets:		
Goodwill	163,474	163,474
Gas stored underground	175,304	161,537
Costs recoverable from customers	15,210	19,767
Other	31,582	33,929
Total other assets	385,570	378,707
Total Assets	$ 3,823,175	$ 2,951,299

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

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BOARDWALK PIPELINE PARTNERS, LP

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

LIABILITIES AND PARTNERS' CAPITAL	**September 30, 2007**	**December 31, 2006**
Current Liabilities:		
Payables:		
Trade	$ 139,202	$ 56,604
Affiliates	1,127	3,014
Other	14,336	14,459
Gas Payables:		
Transportation and exchange	11,797	15,485
Storage	40,966	42,127
Other accrued taxes	25,659	16,082
Accrued interest	22,862	19,376
Accrued payroll and employee benefits	16,475	18,198
Deferred income	9,809	22,147
Other current liabilities	30,221	20,926
Total current liabilities	312,454	228,418
Long –Term Debt	1,847,534	1,350,920
Other Liabilities and Deferred Credits:		
Pension and postretirement benefits	17,658	15,761
Asset retirement obligation	14,751	14,307
Provision for other asset retirement	41,648	39,644
Other	29,992	29,742
Total other liabilities and deferred credits	104,049	99,454
Commitments and Contingencies		
Partners' Capital:		
Common units - 83,156,122 units and 75,156,122 units issued and outstanding as of September 30, 2007 and December 31, 2006	1,232,734	941,792
Subordinated units - 33,093,878 units issued and outstanding as of September 30, 2007 and December 31, 2006	287,538	285,543
General partner	28,122	22,060
Accumulated other comprehensive income	10,744	23,112
Total partners' capital	1,559,138	1,272,507
Total Liabilities and Partners' Capital	$ 3,823,175	$ 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 September 30,		For the Nine Months Ended September 30,	
	2007	2006	2007	2006
Operating Revenues:				
Gas transportation	$ 111,572	$ 108,195	$ 379,494	$ 364,597
Parking and lending	6,845	9,099	38,024	32,030
Gas storage	10,256	8,321	28,455	25,136
Other	6,059	7,430	27,413	14,390
Total operating revenues	134,732	133,045	473,386	436,153
Operating Costs and Expenses:				
Operation and maintenance	45,863	39,740	128,317	114,901
Administrative and general	22,103	23,878	70,011	74,111
Depreciation and amortization	20,510	18,888	60,644	56,298
Taxes other than income taxes	6,588	6,592	21,757	18,607
Asset impairment	-	-	14,698	-
Net (gain) on disposal of operating assets and related contracts	(8,879)	(826)	(7,241)	(3,032)
Total operating costs and expenses	86,185	88,272	288,186	260,885
Operating income	48,547	44,773	185,200	175,268
Other Deductions (Income):				
Interest expense	14,760	14,977	46,106	45,822
Interest income	(5,741)	(553)	(16,283)	(1,796)
Interest income from affiliates, net	(16)	(10)	(36)	(16)
Miscellaneous other deductions (income), net	(575)	(406)	(751)	(1,383)
Total other deductions	8,428	14,008	29,036	42,627
Income before income taxes	40,119	30,765	156,164	132,641
Income taxes	140	118	503	364
Net income	$ 39,979	$ 30,647	$ 155,661	$ 132,277
Calculation of limited partners' interest in Net income:				
Net income	$ 39,979	$ 30,647	$ 155,661	$ 132,277
Less general partner's interest in Net income	1,511	612	4,521	2,645
Limited partners' interest in Net income	$ 38,468	$ 30,035	$ 151,140	$ 129,632
Basic and diluted net income per limited partner unit:				
Common units	$ 0.35	$ 0.35	$ 1.32	$ 1.27
Subordinated units	$ 0.30	$ 0.19	$ 1.32	$ 1.27

Cash distribution to common and subordinated unitholders	$ 0.44	$ 0.38	$ 1.29	$ 0.92
Weighted-average number of limited partner units outstanding:				
Common units	83,156,122	68,256,122	80,773,769	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 Nine Months Ended September 30, 2007	For the Nine Months Ended September 30, 2006
OPERATING ACTIVITIES:		
Net income	$ 155,661	$ 132,277
Adjustments to reconcile to cash provided by operations:		
Depreciation and amortization	60,644	56,298
Amortization of deferred costs	1,161	1,746
Amortization of acquired executory contracts	(994)	(3,236)
Asset impairment	14,698	-
(Gain) loss on disposal of operating assets and related contracts	(7,241)	(3,032)
Changes in operating assets and liabilities:		
Trade and other receivables	16,376	13,637
Gas receivables and storage assets	(2,195)	24,417
Costs recoverable from customers	4,471	2,584
Other assets	(14,120)	(12,104)
Trade and other payables	(15,325)	(369)
Gas payables	(11,087)	(54,079)
Accrued liabilities	11,340	(5,304)
Other liabilities	15,348	31,949
Net cash provided by operating activities	228,737	184,784
INVESTING ACTIVITIES:		
Capital expenditures	(688,155)	(124,175)
Proceeds from sale of operating assets	5,025	3,967
Proceeds from insurance reimbursements and other recoveries	1,726	4,960
Advances to affiliates, net	187	(660)
Purchase of short-term investments	(540,000)	-
Net cash used in investing activities	(1,221,217)	(115,908)
FINANCING ACTIVITIES:		
Payments of notes payable	-	(42,100)
Proceeds from long-term debt	495,271	60,000
Distributions	(150,479)	(95,021)
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	638,609	(77,108)
(Decrease) in cash and cash equivalents	(353,871)	(8,232)
Cash and cash equivalents at beginning of period	399,032	65,792
Cash and cash equivalents at end of period	$ 45,161	$ 57,560

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

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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	87,303	42,329	2,645	-	132,277
Distributions paid	(62,714)	(30,407)	(1,900)	-	(95,021)
Other comprehensive income	-	-	-	3,602	3,602
Transaction costs related to sale of common units	13	-	-	-	13
Balance, September 30, 2006	$ 730,211	$ 278,500	$ 17,406	$ 3,428	$ 1,029,545

Balance, January 1, 2007	$ 941,792	$ 285,543	$ 22,060	$ 23,112	$ 1,272,507
Add (deduct):					
Net income	106,620	44,520	4,521	-	155,661
Distributions paid	(103,536)	(42,525)	(4,418)	-	(150,479)
Other comprehensive (loss)	-	-	-	(12,368)	(12,368)
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, September 30, 2007	$ 1,232,734	$ 287,538	$ 28,122	$ 10,744	$ 1,559,138

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 September 30, 2007	For the Three Months Ended September 30, 2006	For the Nine Months Ended September 30, 2007	For the Nine Months Ended September 30, 2006
Net income	$ 39,979	$ 30,647	$ 155,661	$ 132,277
Other comprehensive income:				
(Loss) gain on cash flow hedges	(5,765)	1,328	(4,869)	11,736
Reclassification adjustment transferred to Net income	(2,889)	(2,540)	(7,499)	(8,134)
Total comprehensive income	$ 31,325	$ 29,435	$ 143,293	$ 135,879

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

BOARDWALK PIPELINE PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

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 Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America 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 September 30, 2007 and December 31, 2006, and the results of operations for the three and nine months ended September 30, 2007 and 2006 and changes in cash flow for the nine months ended September 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 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 $41.8 million and $45.7 million at September 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 September 30, 2007 and December 31, 2006, Gulf South held 53.1 trillion British thermal units (TBtu) and 61.0 TBtu of gas owned by shippers. Gulf South loaned 0.6 TBtu of gas to shippers as of September 30, 2007. No gas was loaned by Gulf South to shippers as of 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 price 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.

Certain volumes of gas stored underground are available for sale and subject to commodity price risk. At September 30, 2007 and December 31, 2006, approximately $14.3 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 became 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 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 and were settled in March 2007 when the sales price was determined. 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 first quarter 2007. The derivatives related to the remaining 1.8 Bcf of storage gas were not designated as cash flow hedges in accordance with SFAS No. 133 and have been marked to fair value through earnings. In the third quarter 2007, approximately 0.9 Bcf of this gas was sold and the related derivatives were settled resulting in a gain of $4.4 million. The gain is included in Net (gain) loss on disposal of operating assets and related contracts on the Condensed Consolidated Statements of Income.

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, approximately 1.3 Bcf of which remained outstanding at September 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 $0.4 and $1.1 million for the three and nine months ended September 30, 2007.

In August 2007, the Partnership entered into a Treasury rate lock for a notional amount of $150.0 million of principal to hedge the risk attributable to changes in the risk-free component of forward 10-year interest rates through February 1, 2008. The reference rate on the rate lock is 4.74%. Under the terms of the rate lock, the counterparty would pay the Partnership a settlement amount if the 10-year Treasury rate is greater than the reference rate on February 1, 2008. Conversely, the Partnership would pay the counterparty a settlement amount if the 10-year Treasury rate is less than the reference rate. The Treasury rate lock was designated as a cash flow hedge in accordance with SFAS No. 133. As of September 30, 2007, the Partnership recorded a payable of $1.6 million and a corresponding amount in Accumulated other comprehensive income for the fair value of the rate lock.

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 were 5.00% and 4.96%. The rate locks were designated as cash flow hedges in accordance with SFAS No. 133. In August 2007, the rate locks were settled resulting in payments to the counterparties of approximately $3.9 million. The effective amount of the hedge of approximately $3.4 million, which was recorded in Accumulated other comprehensive income, will be amortized to interest expense over the 10-year term of the related notes which were issued in August 2007.

With the exception of the derivatives related to storage gas volumes and line pack gas purchases referred to above, the derivatives related to the sale or purchase of natural gas, cash for fuel reimbursement and debt issuance generally qualify for cash flow hedge accounting under SFAS No. 133 and are designated as such. 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 anticipated transactions affect earnings. 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 (gain) 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.

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

	September 30, 2007	December 31, 2006
Prepaid expenses and other current assets	$ 1.7	$ 13.7
Other Assets - Other	0.2	-
Other current liabilities	1.9	5.1
Other Liabilities and Deferred Credits - Other	1.0	-
Accumulated other comprehensive income	(2.5)	8.3

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 earnings. Ineffectiveness recorded during the three and nine month periods ended September 30, 2007 increased Net income by $0.5 million and $0.9 million. The Partnership did not record any ineffectiveness during the three and nine month periods ending September 30, 2006. The Partnership did not discontinue any cash flow hedges during the three and nine months ended September 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 the Partnership does not have access to the information about each partner's tax attributes. 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 third quarter 2007, the Partnership accrued estimated insurance proceeds of $5.1 million for claims related to Hurricane Rita which represented the minimum amount of insurance proceeds that were probable of recovery. This amount resulted in a reduction of Operating Costs and Expenses. Also in the third quarter 2007, because the remediation work related to the hurricanes was completed, the remaining accrued liability of $0.7 million was reversed to income as a component of Operating Costs and Expenses. In the first quarter 2007, the Partnership received a final cash payment of $6.2 million of insurance proceeds related to damages incurred during Hurricane Katrina, $4.7 million of which was applied against a receivable and $1.5 million of which was recognized in Gas transportation revenue.

In the third quarter 2006, the liability was increased by $0.9 million with a corresponding charge to earnings. Operating Costs and Expenses were favorably impacted by $2.6 million related to the hurricanes, during the nine months ended September 30, 2006, mainly due to the recognition of $2.7 million of insurance proceeds that were probable of recovery. The accrued liability for the hurricanes was zero and $1.0 million as of September 30, 2007, and December 31, 2006.

Through September 30, 2007, the Partnership has received a total of approximately $12.2 million in insurance proceeds related to Hurricane Katrina, and will continue to pursue additional recovery of insurance proceeds related to Hurricane Rita.

B. South Timbalier Bay Pipeline Assets

In conjunction with a review of its offshore pipeline assets in the South Timbalier Bay area, offshore Louisiana, Gulf South discovered that approximately 8 to 9 miles of offshore pipeline does not have adequate cover. In the third quarter, the Partnership accrued a liability of $4.0 million, which was charged to Operation and maintenance expense, for the estimated cost to re-bury the pipeline. Gulf South will continue to explore alternatives to mitigate these costs while complying with applicable regulations.

C. 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 $8.1 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 September 30, 2007, Gulf South has received $1.0 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 alleged 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. On October 18, 2007, the FERC issued an order dismissing the complaint. NET can request a rehearing within thirty days of the order.

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.

D. Regulatory and Rate Matters

Pipeline Expansion Projects

East Texas to Mississippi Expansion. On June 18, 2007, the FERC granted Gulf South the 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 of new peak-day 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 6.8 years), for 1.4 Bcf per day of capacity from Carthage, Texas, which represents substantially all of the normal operating capacity. Construction of this project has commenced and the Partnership expects this project to be in service during the later part of 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 of peak-day transmission capacity. 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 Enogex, 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. A customer's option for an additional 300 MMcf per day of firm transportation capacity expired on October 1, 2007. Another customer has the option through November 30, 2007 to increase its contract capacity by 50 MMcf per day. 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 later part of the fourth quarter 2008. The Partnership is no longer engaged in negotiations for the possible sale of up to a 49.0% equity interest in Gulf Crossing to one of the foundation shippers on the project.

Southeast Expansion. On September 28, 2007, the FERC granted Gulf South the authority to construct, own and operate a pipeline expansion originating near Harrisville, Mississippi and extending to an interconnect with Transco 85. This expansion will initially consist of approximately 112 miles of 42-inch pipeline having capacity of approximately 1.2 Bcf of peak-day transmission capacity, and will be expanded to 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 for capacity which will enhance Gulf South's access to 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 Partnership expects to commence construction in the fourth quarter 2007, and this expansion to be in service during the later part of the first quarter 2008.

Fayetteville and Greenville Laterals. The Partnership is pursuing the construction of two laterals connected to its Texas Gas 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 of peak-day transmission capacity. 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 approximately 750 MMcf of peak-day transmission capacity, will originate at the Texas Gas 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 the first 60 miles of the Fayetteville Lateral to be in service during the early part of the third quarter 2008 and the remainder of the Fayetteville and Greenville Laterals to be in service during the first quarter 2009.

Pipeline Expansion Project Costs. The total cost of the pipeline expansion projects discussed above is estimated to be approximately $3.7 billion. These costs include the expanded pipeline capacity necessary to accommodate additional volumes from certain assumed capacity options, 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 penalties and stand-by costs.

Storage Expansion Projects

Western Kentucky Storage Expansion Phase II. 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 (with a weighted-average term of 8.3 years) for the full additional capacity at Texas Gas' maximum applicable rate. The Partnership expects this project to cost approximately $56.0 million and to be in service November 2007.

Western Kentucky Storage Expansion Phase III. Texas Gas has signed two 10-year precedent agreements for 4.0 Bcf of storage capacity for its Phase III storage project. 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. The cost of this project will be dependent on the ultimate size of the expansion. The Partnership expects 4.0 Bcf of storage capacity to be in service in 2008.

Magnolia Storage Facility. The Partnership was developing a salt dome storage cavern near Napoleonville, Louisiana. Operational tests, which began in May 2007 and were completed in July, 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 SFAS 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. Additional costs to abandon the impaired cavern may be incurred due to regulatory or contractual obligations, however the amounts are inestimable at this time.

Contract Termination Payment

The Partnership terminated its agreement with one of its construction contractors on the Southeast Expansion project effective September 30, 2007, to avoid a cost increase associated with the delay of construction. Another contractor was selected at more favorable pricing terms to perform the work that would have been performed under the terminated contract. This decision will not have an effect on the project schedule. The cost to terminate the construction contract of $3.8 million was recorded in Operation and maintenance expense.

Pipeline Integrity

The Office of Pipeline Safety has issued a final rule that requires natural gas pipeline operators to develop integrity management programs. The Partnership expenses all costs incurred in the development of its integrity management program and the ongoing inspecting, testing and reporting on the condition of the pipeline system. Costs incurred to replace segments of pipeline or install software or equipment are capitalized to the extent they meet the requirements in the Partnership's capitalization policy for those types of expenditures. The estimated costs to comply with the rule during the initial ten-year baseline period ending in 2012 range from $110.0 to $115.0 million. As of September 30, 2007, the Partnership has invested approximately $12.3 million to develop and implement integrity management program computer systems 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.

E. 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 September 30, 2007 and December 31, 2006, the Partnership had an accrued liability of approximately $17.5 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 ten 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 September 30, 2007 and December 31, 2006, approximately $2.7 and $3.5 million were recorded in Other current liabilities. As of September 30, 2007 and December 31, 2006, approximately $14.8 million and $14.9 million were 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 September 30, 2007, the Partnership had incurred costs of approximately $16.1 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.

F. Commitments for Construction

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

Less than 1 year	$	755.2
1-3 years		145.2
4-5 years		-
More than 5 years		-
Total	$	900.4

The construction work in progress included in Property, plant and equipment, net in the Condensed Consolidated Balance Sheets was $960.2 million and $166.0 million as of September 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 nine month periods ended September 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	**For the Nine Months Ended**

	September 30,		September 30,	
	2007	**2006**	**2007**	**2006**
Limited partners' interest in net income	$ 38,468	$ 30,035	$ 151,140	$ 129,632
Less assumed allocation to incentive distribution rights	(711)	-	719	962
Net income available to limited partners	$ 39,179	$ 30,035	$ 150,421	$ 128,670
Less assumed allocation to subordinated units	10,074	6,144	43,718	42,015
Net income available to common units	$ 29,105	$ 23,891	$ 106,703	$ 86,655
Weighted average common units	83,156,122	68,256,122	80,773,769	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	$ 1.32	$ 1.27
Net income per limited partner unit – subordinated units	$ 0.30	$ 0.19	$ 1.32	$ 1.27

Note 7: Financing

On August 17, 2007, the Partnership received net proceeds of approximately $495.3 million after deducting initial purchaser discounts and offering expenses of $4.7 million from Gulf South's sale of $225.0 million of 5.75% senior unsecured notes due August 15, 2012, and $275.0 million of 6.30% senior unsecured notes due August 15, 2017. Interest on the notes will be payable on February 15 and August 15 of each year, beginning on February 15, 2008. The notes are redeemable, in whole or in part, at Gulf South's option at any time, at a redemption price equal to the greater of 100% of the principal amount of the notes to be redeemed or a "make whole" redemption price based on the remaining scheduled payments of principal and interest discounted to the date of redemption at a Treasury rate plus 20 basis points in the case of the 2012 notes, or 25 basis points in the case of the 2017 notes, plus accrued and unpaid interest, if any. Other customary covenants apply, including those concerning events of default.

As of September 30, 2007 and December 31, 2006, no funds were drawn under the Partnership's $700 million revolving credit facility. However, at September 30, 2007, the Partnership had outstanding letters of credit under the facility for $221.5 million to support certain obligations associated with the Fayetteville Lateral and Gulf Crossing expansion projects which reduced the available capacity under the facility by such amount.

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 September 30, 2007 and December 31, 2006, the weighted average interest rate of the Partnership's long-term debt was 5.82% and 5.41%. The Partnership was in compliance with all loan covenants at September 30, 2007.

During the three and nine months ended September 30, 2007, the Partnership capitalized interest of $8.2 million and $14.5 million. During the three and nine months ended September 30, 2006, the Partnership capitalized interest of approximately $0.7 million and $0.8 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 $1.3 million and $2.4 million of AFUDC for the three and nine months ended September 30, 2007. The Partnership capitalized $0.5 million and $1.1 million of AFUDC for the three and nine months ended September 30, 2006.

Note 8: Investment in Securities Under Repurchase Agreements

During the third quarter 2007, the Partnership began investing its undistributed cash in U.S. Government securities, primarily Treasury notes, under repurchase agreements. Generally, the Partnership has engaged in overnight repurchase transactions where purchased securities are sold back to the counterparty the following business day. Pursuant to the master repurchase agreements, the Partnership takes actual possession of the purchased securities. In the event of default by the counterparty under the agreement, the repurchase would be deemed immediately to occur and the Partnership would be entitled to sell the securities in the open market, or give the counterparty credit based on the market price on such date, and apply the proceeds (or deemed proceeds) to the aggregate unpaid repurchase amounts and any other amounts owing by the counterparty. Previously, the Partnership's cash balances were invested in money market accounts.

At September 30, 2007, the portfolio consisted of two tranches of Treasury securities purchased in overnight repurchase agreement transactions, each in the amount of $270.0 million, with original maturities in August 2008 and January 2011. The amount invested under repurchase agreements of $540.0 million, stated at cost which closely approximates the fair values of the securities, is presented as Short-term investments in Current Assets on the

Condensed Consolidated Balance Sheets.

Note 9: Credit Concentration

Natural gas price volatility has increased dramatically in recent years which has materially increased credit risk related to gas loaned to customers. Gas loaned to customers refers to receivables for services provided, as well as volumes owed by customers for imbalances or gas lent by the Partnership to them, generally under PAL and no-notice service (NNS). As of September 30, 2007, the amount of gas loaned out by the Partnership's subsidiaries was approximately 6.6 TBtu and, assuming an average market price during September 2007 of $5.86 per million British thermal units (MMBtu), the market value of gas loaned out at September 30, 2007, would have been approximately $38.7 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 10: Employee Benefits

Substantially all of Texas Gas' employees are covered under a non-contributory, defined benefit pension plan. 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 provides postretirement life insurance and postretirement health care benefits to certain retired employees. The operating subsidiaries also provide 401(k) plan benefits to their 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 2007, the Partnership recognized a pension settlement charge in Administrative and general expense related to the ERIP of $4.2 million to recognize the effects of retirements associated with the ERIP that were initiated during the period. In third quarter 2006, as a result of the ERIP, the Partnership recognized a special termination benefit of approximately $5.6 million for pension and $0.9 million for post retirement benefits other than pensions (PBOP).

Components of Net Periodic Benefit Cost

Components of net periodic benefit cost for both the retirement plans and PBOP for the three and nine months ended September 30, 2007 and 2006 were the following (in thousands):

	Retirement Plans For the Three Months Ended September 30,		PBOP For the Three Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Service cost	$ 935	$ 1,826	$ 152	$ 108
Interest cost	1,542	2,816	818	858
Expected return on plan assets	(1,695)	(2,942)	(1,183)	(1,134)
Amortization of prior service credit	1	-	(1,940)	(1,939)
Amortization of unrecognized net loss	69	383	167	110
Settlement charge (ERIP)	400	5,600	-	900
Regulatory asset (increase) decrease	(453)	(3,295)	1,354	1,354
Net periodic expense	$ 799	$ 4,388	$ (632)	$ 257

	Retirement Plans For the Nine Months Ended September 30,		PBOP For the Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Service cost	$ 2,800	$ 3,984	$ 456	$ 1,194
Interest cost	4,767	6,044	2,455	4,319
Expected return on plan assets	(5,275)	(6,492)	(3,550)	(3,418)

Amortization of prior service credit	3	-	(5,820)	(2,587)
Amortization of unrecognized net loss	215	584	501	876
Settlement charge (ERIP)	4,200	5,600	-	900
Regulatory asset (increase) decrease	(453)	(3,045)	4,061	4,964
Net periodic expense	$ 6,257	$ 6,675	$ (1,897)	$ 6,248

The decrease in the regulatory asset for PBOP was due primarily to the amortization of costs incurred in prior years. The regulatory asset for the retirement plans was increased due to the accumulated cost for the year exceeding the expense cap established in the 2005 rate case settlement between Texas Gas and its customers. In accordance with the rate case settlement, Texas Gas is permitted to seek future rate recovery for amounts of annual pension costs in excess of $6.0 million.

Defined Contribution Plans

Costs related to the Partnership's defined contribution plans were $1.2 million and $3.9 million for the three and nine months ended September 30, 2007, and $1.2 million and $3.7 million for the three and nine months ended September 30, 2006.

Note 11: 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 $2.7 million and $9.3 million for the three and nine months ended September 30, 2007, and $2.1 million and $8.6 million for the three and nine months ended September 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 $115.4 million and $81.2 million during the nine months ended September 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 12: 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
November 5, 2007	November 12, 2007	0.45
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 $1.4 million for the nine months ended September 30, 2007, and will be $1.1 million in the fourth quarter 2007 based on the declared distribution.

Note 13: Accumulated Other Comprehensive Income

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

	As of September 30, 2007	As of December 31, 2006
(Loss) gain on cash flow hedges	$ (2,524)	$ 8,309
Deferred components of net periodic benefit cost	13,268	14,803
Total Accumulated other comprehensive income	$ 10,744	$ 23,112

Note 14: Guarantee of Securities of Subsidiaries

The Partnership has no 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 September 30, 2007.

Note 15: 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 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 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 September 30, 2007 and 2006

Our net income for the third quarter 2007 increased $9.4 million, or 30.7%, from the comparable 2006 period. The primary drivers for the increase were higher revenues from firm transportation services resulting from higher reservation rates and pipeline system expansion.

Operating revenues for the third quarter 2007 increased $1.7 million, or 1.3%, to $134.7 million, compared to $133.0 million for the third quarter 2006 primarily due to:

- $5.1 million increase in transportation fees due to higher reservation rates, including $2.4 million from new contracts associated with the Carthage, Texas to Keatchie, Louisiana pipeline expansion which was placed in service at the end of 2006, partly offset by

  - a $2.5 million decrease in fuel revenues due to lower realized gas prices, including hedging activity.

Operating expenses for the third quarter 2007 decreased $2.1 million, or 2.4%, to $86.2 million, compared to $88.3 million for the third quarter 2006 primarily due to:

- $6.7 million decrease comprised of a $5.1 million accrual of estimated insurance proceeds deemed probable of recovery related to Hurricane Rita and a $1.6 million decrease in the estimated cost of damage caused by Hurricanes Katrina and Rita (hurricanes);
- $4.4 million gain on the sale of gas associated with the Western Kentucky storage expansion project and related derivative contracts;
- $1.8 million decrease in administrative and general expenses driven primarily by benefit plan changes at Texas Gas, partly offset by an increase in other expenses due to growth; and

The decreases were partly offset by:

- $4.0 million increase from an accrual for remediation of an offshore pipeline in the South Timbalier Bay area, offshore Louisiana;
- $3.8 million increase related to termination of an agreement with a construction contractor on the Southeast expansion project;
- $2.1 million increase in fuel costs due to an increase in gas usage; and
- $1.6 million increase in depreciation and amortization from additions to plant and computer systems.

Total other deductions for the third quarter 2007 declined by $5.6 million, or 40.0%, to $8.4 million, compared to $14.0 million for the third quarter 2006, primarily due to an increase in interest income of $5.1 million as a result of higher levels of invested cash.

Results of Operations for the Nine Months Ended September 30, 2007 and 2006

Our net income for the first nine months of 2007 increased $23.4 million or 17.7% 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 higher operating expenses.

Operating revenues for the nine months ended September 30, 2007 increased $37.2 million, or 8.5%, to $473.4 million, compared to $436.2 million for the nine months ended September 30, 2006 primarily due to:

- $18.8 million increase in transportation fees due to higher reservation rates, including $6.6 million from new contracts associated with the Carthage, Texas to Keatchie, Louisiana pipeline expansion;
- $11.5 million increase in fuel revenues due to an increase in other system volumes and higher realized gas prices including hedging activity; and
- $9.3 million increase in PAL and storage services mainly due to increased firm storage service rates and gas parked by customers during summer and fall 2006 for withdrawal during summer 2007.

The increases were partly offset by:

- $2.2 million due to a decrease in the amortization of acquired executory contracts.

Operating expenses for the nine months ended September 30, 2007 increased $27.3 million, or 10.5%, to $288.2 million, compared to $260.9 million for the nine months ended September 30, 2006 primarily due to:

- $14.7 million loss from impairment of the Magnolia storage facility in the second quarter 2007;
- $5.0 million increase in fuel costs due to an increase in gas usage;
- $4.3 million increase in depreciation and amortization from additions to plant and computer systems;
- $4.0 million increase from an accrual for remediation of an offshore pipeline in the South Timbalier Bay area, offshore Louisiana;
- $3.8 million increase related to termination of an agreement with a construction contractor on the Southeast expansion project; and
- $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.

The increases were partly offset by:

- $4.1 million decrease in administrative and general expenses driven primarily by benefit plan changes at Texas Gas, partly offset by an increase in other expenses due to growth;
- $3.6 million net favorable variance from a gain on the sale of gas associated with the Western Kentucky storage expansion project and related derivative contracts; and
- $3.0 million decrease from the accrual of estimated insurance proceeds related to the hurricanes deemed probable of recovery.

Total other deductions for the nine months ended September 30, 2007 declined by $13.6 million, or 31.9%, to $29.0 million, compared to $42.6 million for the nine months ended September 30, 2006. The decline is primarily due to an increase in interest income of $14.5 million as a result of higher levels of invested cash.

Capital Expenditures

Capital expenditures for the nine months ended September 30, 2007 and 2006 were $688.2 million and $124.2 million. For the year ending December 31, 2007, we expect to make capital expenditures of approximately $1.3 billion, of which we expect approximately $1.2 billion to be for the expansion projects discussed below and approximately $62.4 million to be for maintenance capital. The amount of 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 cash on hand, liquidation of short-term investments, proceeds from additional 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 any future financing activities. We expect to fund our maintenance capital expenditures from operating cash flows.

We are currently engaged in the following pipeline expansion projects:

- *East Texas to Mississippi Expansion.* On June 18, 2007, the FERC granted Gulf South the 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 billion cubic feet (Bcf) of new peak-day 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 6.8 years), for 1.4 Bcf per day of capacity from Carthage, Texas, which represents substantially all of the normal operating capacity. Construction of this project has commenced and we expect this project to be in service during the later part of the fourth quarter 2007.

In September 2007, Gulf South became aware of allegations by two former employees of a manufacturer of pipe to be installed as part of the East Texas to Mississippi expansion project that certain irregularities occurred during the manufacturing process. Gulf South has conducted an investigation into these allegations and informed appropriate government officials. Gulf South has, among other things, interviewed the complainants and other individuals and reviewed documentation related to the manufacture and inspection of the pipe, including radiographic records related to allegedly deficient pipe welds, and has found no evidence to support these allegations. Based on these results, we believe that the subject pipe meets our specifications and is suitable to be placed into service.

- *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 of peak-day transmission capacity. 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 Enogex, 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. A customer's option for an additional 300 MMcf per day of firm transportation capacity expired on October 1, 2007. Another customer has the option through November 30, 2007, to increase its contract capacity by 50 MMcf per day. 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 later part of the fourth quarter 2008. We are no longer engaged in negotiations for the possible sale of up to a 49.0% equity interest in Gulf Crossing to one of the foundation shippers on the project.

- *Southeast Expansion.* On September 28, 2007, the FERC granted Gulf South the authority to construct, own and operate a pipeline expansion originating near Harrisville, Mississippi and extending to an interconnect with Transco 85. This expansion will initially consist of approximately 112 miles of 42-inch pipeline having capacity of approximately 1.2 Bcf of peak-day transmission capacity, and will be expanded to 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 for capacity which will enhance Gulf South's access to 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. We expects to commence construction in the fourth quarter 2007, and this expansion to be in service during the later part of the first quarter 2008.

- *Fayetteville and Greenville Laterals.* We are pursuing the construction of two laterals connected to our Texas Gas 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 of peak-day transmission capacity. 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 of peak-day transmission capacity, will originate at the Texas Gas 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 the first 60 miles of the Fayetteville Lateral to be in service during the early part of the third quarter 2008 and the remainder of the Fayetteville and Greenville Laterals to be in service during the first quarter 2009.

Pipeline Expansion Costs. The total cost of the pipeline expansion projects discussed above is estimated to be approximately $3.7 billion. These costs include the expanded pipeline capacity necessary to accommodate additional volumes from certain assumed capacity options, 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 penalties and stand-by costs.

In addition to the pipeline expansion projects described above, we are currently engaged in the following storage expansion projects:

- *Western Kentucky Storage Expansion Phase II.* 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 (with a weighted-average term of 8.3 years), for the full additional capacity at Texas Gas' maximum applicable rate. We expect this project to cost approximately $56.0 million and to be in service November 2007.

- *Western Kentucky Storage Expansion Phase III.* Texas Gas has signed two 10-year precedent agreements for 4.0 Bcf of storage capacity for our Phase III storage project. 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. The cost of this project will be dependent on the ultimate size of the expansion. We expect 4.0 Bcf of storage capacity to be in service in 2008.

- *Magnolia Storage Facility.* We were developing a salt dome storage cavern near Napoleonville, Louisiana. Operational tests, which began in May 2007 and were completed in July, 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 (SFAS) 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. Additional costs to abandon the impaired cavern may be incurred due to regulatory or contractual obligations, however, the amounts are inestimable at this time.

Distributions

Note 12 of the Notes to Condensed Consolidated Financial Statements 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. We use cash provided from our subsidiaries and, as needed, borrowings under our revolving credit facility to service our indebtedness and make distributions to unitholders and our general partner.

During the third quarter 2007, Gulf South sold $225.0 million of 5.75% senior unsecured notes due August 15, 2012, and $275.0 million of 6.30% senior unsecured notes due August 15, 2017. We received net proceeds of approximately $495.3 million after deducting initial purchaser discounts and offering expenses of $4.7 million. The proceeds will primarily be used to fund capital expenditures associated with our expansion projects.

As of September 30, 2007, and December 31, 2006, no funds were drawn under our $700 million revolving credit facility. However, at September 30, 2007, we had outstanding letters of credit under the facility for $221.5 million to support certain obligations associated with the Fayetteville Shale and Gulf Crossing expansion projects which reduced the available capacity under the facility by such amount.

During the third quarter 2007, we began investing our cash and cash equivalents in U.S. Government securities, primarily Treasury notes, under repurchase agreements. Generally, we have engaged in overnight repurchase transactions where purchased securities are sold back to the counterparty the following business day. Pursuant to the master repurchase agreements, we take actual possession of the purchased securities. In the event of default by the counterparty under the agreement, the repurchase would be deemed immediately to occur and we would be entitled to sell the securities in the open market, or give the counterparty credit based on the market price on such date, and apply the proceeds (or deemed proceeds) to the aggregate unpaid repurchase amounts and any other amounts owing by the counterparty. Note 8 of the Notes to Condensed Consolidated Financial Statements in Item 1 of this Report contains more information about our investments under the program.

Changes in cash flow from operating activities

Net cash provided by operating activities increased $43.9 million, or 23.8%, to $228.7 million for the nine months ended September 30, 2007, compared to $184.8 million for the comparable 2006 period, primarily due to:

- $44.1 million improvement in net income, excluding non-cash items such as depreciation and amortization and the Magnolia impairment charge;
- $21.9 million increase in cash due to gas purchases of imbalance gas made in 2006; and
- $18.0 million increase in cash due to the timing of expenditures.

These increases were partly offset by:

- $32.9 million reduction in cash due to recognition of deferred income related to PAL services..

Changes in cash flow from investing activities

Net cash used in investing activities increased $1.1 billion to $1.2 billion for the nine months ended September 30, 2007, compared to $115.9 million for the comparable 2006 period, primarily due to:

- $564.0 million increase in capital expenditures mainly for our expansion projects; and
- $540.0 million increase in purchases of short-term investments.

Changes in cash flow from financing activities

Net cash provided by (used in) financing activities increased $715.7 million to $638.6 million for the nine months ended September 30, 2007, compared to a use of $77.1 million for the comparable 2006 period, primarily due to:

- $293.8 million in net proceeds from the sale of 8,000,000 units and related general partner capital contribution in March 2007; and
- $495.3 million in net proceeds from the issuance of long term debt at Gulf South.

These increases were partly offset by:

- $55.5 million increase in cash distributions to unitholders and the general partner.

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	$ 900.4	$ 755.2	$ 145.2	$ -	$ -

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 September 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, disclosed or both, depending on the circumstances, 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 storage cavern. In determining that the fair value of the cavern was zero, estimates and assumptions were made regarding the cash flows associated with the storage cavern disposal through sale or abandonment. Certain costs remain inestimable related to potential regulatory or contractual obligations associated with abandonment of the storage cavern. We believe that alternative uses for the storage cavern may be possible in the hands of a third-party, and will pursue these options with the lessor, however, we have assumed no future cash flows related to these options in our impairment analysis. 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 nine months ended September 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 including contracted volumes 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 September 30, 2007, had a carrying value of $1.8 billion and a fair value of $1.8 billion. The weighted-average interest rate of our long-term debt was 5.82% at September 30, 2007.

In August 2007, we entered into a Treasury rate lock for a notional amount of $150.0 million of principal to hedge the risk attributable to changes in the risk-free component of forward 10-year interest rates through February 1, 2008. The reference rate on the rate lock is 4.74%. Under the terms of the rate lock, the counterparty would pay us a settlement amount if the 10-year Treasury rate is greater than the reference rate on February 1, 2008. Conversely, the Partnership would pay the counterparty a settlement amount if the 10-year Treasury rate is less than the reference rate. A 10 basis point increase in the 10-year Treasury rate would result in a $1.2 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 $1.2 million unfavorable change in the value of the rate locks. The Treasury rate lock was designated as a cash flow hedge in accordance with SFAS No. 133. As of September 30, 2007, we recorded a payable of $1.6 million and a corresponding amount in Accumulated other comprehensive income for the fair value of the rate lock.

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 were 5.00% and 4.96%. The rate locks were designated as cash flow hedges in accordance with SFAS No. 133. In August 2007, the rate locks were settled resulting in payments to the counterparties of approximately $3.9 million. The effective amount of the hedge of approximately $3.4 million, which was recorded in Accumulated other comprehensive income, will be amortized to interest expense over the 10-year term of the related notes which were issued in August 2007.

Certain volumes of our gas stored underground are available for sale and subject to commodity price risk. At September 30, 2007 and December 31, 2006, approximately $14.3 million and $14.0 million of gas stored underground at the Gulf South facilities, which we own and carry as current Gas stored underground, is exposed to commodity price risk. We utilize 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 Bcf of gas stored underground with a book value of $11.3 million became 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. We 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 and were settled in March 2007 when the sales price was determined. 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 first quarter 2007. The derivatives related to the remaining 1.8 Bcf of storage gas were not designated as cash flow hedges in accordance with SFAS No. 133 and have been marked to fair value through earnings. In the third quarter 2007, approximately 0.9 Bcf of this gas was sold and the related derivatives were settled, resulting in a gain of $4.4 million. The gain is included in Net (gain) loss on disposal of operating assets and related contracts on the Condensed Consolidated Statements of Income.

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 1.3 Bcf of which remained outstanding at September 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 $0.4 million and $1.1 million for the three and nine months ended September 30, 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 $1.3 million gain in earnings. Conversely, a $1.00 decrease would result in the recognition of a $1.3 million loss.

With the exception of the derivatives related to storage gas volumes and line pack gas purchases referred to above, the derivatives related to the sale or purchase of natural gas, cash for fuel reimbursement and debt issuance generally qualify for cash flow hedge accounting under SFAS No. 133 and are designated as such. 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 anticipated transactions affect earnings. 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 (gain) 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.

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 earnings.

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 September 30, 2007, the amount of gas loaned out by our subsidiaries was approximately 6.6 trillion British thermal units (TBtu) and, assuming an average market price during September 2007 of $5.86 per million British thermal units (MMBtu), the market value of gas loaned out at September 30, 2007 would have been approximately $38.7 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 September 30, 2007, our cash equivalents were invested primarily in Treasury notes under repurchase agreements. 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 nine months ended September 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.

Item1 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. 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 an income 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 establish its income tax allowance. The FERC's *BP West Coast* remand decision, the new income 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 income tax allowance policy and the application of that policy in the December 16, 2005 order. On August 20, 2007, the D.C. Circuit denied rehearing of its decision. If the FERC were to change its income tax allowance policy in the future, such changes could materially and adversely impact the rates we are permitted to charge as future rates are approved for our interstate transportation services.

On December 8, 2006, FERC issued an order in an interstate oil pipeline proceeding addressing its income tax allowance policy, noting that the tax deferral features of a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, which FERC characterized as a "tax savings." FERC stated that it is concerned that this creates an opportunity for those investors to earn an additional return, funded by ratepayers. Responding to this concern, FERC chose to adjust the pipeline's equity rate of return downward based on the percentage by which the publicly traded partnership's cash flow exceeded taxable income. On February 7, 2007, the pipeline asked FERC to reconsider this ruling. On March 9, 2007, FERC granted rehearing for further consideration of its December 8, 2006 order.

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 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, our general partner may elect to require owners of our units to recertify their status as being subject to United States federal income taxation on the income generated by Texas Gas or Gulf South or we may attempt to provide other evidence. We can provide no assurance that the evidence that we will be able to provide (including the information the general partner may require in the certification and recertification process) 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 Texas Gas or Gulf South. If we are unable to establish that the master partnership's unitholders, or its unitholders' owners, incur actual or potential income tax liability 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.

The outcome of certain FERC proceedings involving FERC policy statements is uncertain and could affect the level of return on equity that the Partnership may be able to achieve in any future rate proceeding.

In an effort to provide some guidance and to obtain further public comment on FERC's policies concerning return on equity determinations, on July 19, 2007, FERC issued its Proposed Proxy Policy Statement, *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*. In the Proposed Proxy Policy Statement, FERC proposes to permit inclusion of publicly traded partnerships in the proxy group analysis relating to return on equity determinations in rate proceedings, provided that the analysis be limited to actual publicly traded partnership distributions capped at the level of the pipeline's earnings and that evidence be provided in the form of multiyear analysis of past earnings demonstrating a publicly traded partnership's ability to provide stable earnings over time.

In a decision issued shortly after FERC issued its Proposed Proxy Policy Statement, the D.C.Circuit vacated FERC's orders in proceeding involving *High Island Offshore System* and *Petal Gas Storage.* The Court determined that FERC had failed to adequately reflect risks of interstate pipeline operations both in populating the proxy group (from which a range of equity returns was determined) with entities the record indicated had lower risk, while excluding publicly traded partnerships primarily engaged in interstate pipeline operations, and in the placement of the pipeline under review in each proceeding within that range of equity returns. Although the Court accepted for the sake of argument FERC's rationale for excluding publicly traded partnerships from the proxy group (i.e., publicly traded partnership distributions may exceed earnings) it observed this proposition was "not self-evident."

The ultimate outcome of these proceedings is not certain and may result in new policies being established at FERC that would not allow the full use of publicly traded partnership distributions to unitholders in any proxy group comparisons used to determine return on equity in future rate proceedings. The Partnership cannot ensure that such policy developments would not adversely affect the Partnership's ability to achieve a reasonable level of return on equity in any future rate proceeding.

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

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

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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: October 30, 2007 By: */s/ Jamie L. Buskill*
Jamie L. Buskill
Chief Financial Officer