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

FORM 10-Q

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

For the quarterly period ended September 30, 2006

OR

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

For the transition period from _________ to _________

Commission File No.: 1-16335

Magellan Midstream Partners, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**73-1599053**
(State or other jurisdiction of incorporation or organization)	**(IRS Employer Identification No.)**

One Williams Center, P.O. Box 22186, Tulsa, Oklahoma 74121-2186
(Address of principal executive offices and zip code)

(918) 574-7000
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐

Indicate by check mark whether the registrant is a shell company.
Yes ☐ No ☒

As of November 6, 2006, there were outstanding 66,360,624 common units.

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ITEM 1. FINANCIAL STATEMENTS

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit amounts)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2006	2005	2006
Transportation and terminals revenues	$ 131,647	$ 144,702	$ 370,272	$ 413,448
Product sales revenues	182,129	171,762	457,089	493,464
Affiliate management fee revenue	167	173	501	518
Total revenues	313,943	316,637	827,862	907,430
Costs and expenses:				
Operating	63,379	62,529	159,434	168,220
Environmental	6,942	8,522	9,914	11,261
Product purchases	160,500	169,741	414,159	458,193
Depreciation and amortization	14,498	15,182	41,399	45,739
Affiliate general and administrative	15,784	17,042	46,044	47,806
Total costs and expenses	261,103	273,016	670,950	731,219
Equity earnings	909	814	2,231	2,479
Operating profit	53,749	44,435	159,143	178,690
Interest expense	13,846	14,359	39,508	43,116
Interest income	(1,287)	(482)	(3,429)	(1,729)
Interest capitalized	(299)	(714)	(679)	(1,346)
Debt placement fee amortization	731	679	2,194	2,034
Other (income) expense	—	—	(300)	339
Net income	$ 40,758	$ 30,593	$ 121,849	$ 136,276
Allocation of net income for purposes of calculating earnings per limited partner unit:				
Limited partners' interest	$ 37,143	$ 28,335	$ 105,157	$ 106,163
General partner's interest	3,615	2,258	16,692	30,113
Net income	$ 40,758	$ 30,593	$ 121,849	$ 136,276
Basic net income per limited partner unit	$ 0.56	$ 0.43	$ 1.58	$ 1.60
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	66,361	66,361	66,361	66,361
Diluted net income per limited partner unit	$ 0.56	$ 0.43	$ 1.58	$ 1.60
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	66,592	66,644	66,610	66,537

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2005	September 30, 2006
		(Unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 36,489	$ 73
Restricted cash	5,537	11,170
Accounts receivable (less allowance for doubtful accounts of $133 and $51 at December 31, 2005 and September 30, 2006, respectively)	49,373	58,269
Other accounts receivable	5,566	10,299
Affiliate accounts receivable	5,535	5,209
Inventory	78,155	91,965
Other current assets	5,034	8,317
Total current assets	185,689	185,302
Property, plant and equipment	2,116,143	2,207,761
Less: accumulated depreciation	506,626	545,043
Net property, plant and equipment	1,609,517	1,662,718
Equity investment	24,888	24,292
Long-term accounts receivable	7,327	7,026
Long-term affiliate accounts receivable	1,245	—
Goodwill	24,430	24,033
Other intangibles (less accumulated amortization of $3,607 and $4,804 at December 31, 2005 and September 30, 2006, respectively)	11,652	10,455
Debt placement costs (less accumulated amortization of $6,911 and $8,945 at December 31, 2005 and September 30, 2006, respectively)	8,084	6,477
Other noncurrent assets	3,686	3,532
Total assets	$ 1,876,518	$ 1,923,835
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 25,508	$ 28,316
Affiliate accounts payable	5,821	10,111
Affiliate payroll and benefits	17,028	9,683
Accrued interest payable	9,628	22,639
Accrued taxes other than income	17,307	19,132
Environmental liabilities	30,840	33,118
Deferred revenue	17,522	19,218
Accrued product purchases	34,772	21,766
Current portion of long-term debt	14,345	14,345
Other current liabilities	13,124	26,191
Total current liabilities	185,895	204,519
Long-term debt	782,639	802,233
Long-term affiliate payable	10,091	8,213
Long-term affiliate pension and benefits	9,766	11,415
Other deferred liabilities	52,773	55,184
Environmental liabilities	27,364	26,224
Commitments and contingencies		
Partners' capital:		
Partners' capital	810,045	818,592
Accumulated other comprehensive loss	(2,055)	(2,545)
Total partners' capital	807,990	816,047
Total liabilities and partners' capital	$ 1,876,518	$ 1,923,835

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	Nine Months Ended September 30, 2005	Nine Months Ended September 30, 2006
Operating Activities:		
Net income	$ 121,849	$ 136,276
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	41,399	45,739
Debt placement fee amortization	2,194	2,034
Loss on sale and retirement of assets	8,574	5,435
Equity earnings	(2,231)	(2,479)
Distributions from equity investments	2,150	3,075
Changes in components of operating assets and liabilities:		
Accounts receivable and other accounts receivable	(311)	(12,906)
Affiliate accounts receivable	(455)	326
Inventory	114	(13,810)
Accounts payable	2,132	2,808
Affiliate accounts payable	7,875	4,290
Accrued interest payable	13,248	13,011
Accrued taxes other than income	2,600	1,825
Affiliate payroll and benefits	(6,790)	(7,345)
Accrued product purchases	1,651	(13,006)
Current and noncurrent environmental liabilities	(1,062)	1,138
Other current and noncurrent assets and liabilities	3,840	(2,425)
Net cash provided by operating activities	196,777	163,986
Investing Activities:		
Purchases of marketable securities	(50,500)	—
Sales of marketable securities	138,302	—
Additions to property, plant and equipment	(62,723)	(105,597)
Proceeds from sale of assets	164	1,273
Acquisition of businesses	(55,263)	—
Prepaid construction costs from related party	—	4,500
Net cash used by investing activities	(30,020)	(99,824)
Financing Activities:		
Distributions paid	(115,062)	(153,486)
Borrowings under revolver	—	225,600
Payments on revolver	—	(205,100)
Short-term borrowings	—	7,076
Debt placement costs	—	(427)
Capital contributions by affiliate	19,038	25,742
Other	48	17
Net cash used by financing activities	(95,976)	(100,578)
Change in cash and cash equivalents	70,781	(36,416)
Cash and cash equivalents at beginning of period	29,833	36,489
Cash and cash equivalents at end of period	$ 100,614	$ 73

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Organization and Basis of Presentation

Unless indicated otherwise, the terms “our,” “we,” “us” and similar language refer to Magellan Midstream Partners, L.P. together with our subsidiaries. We are a Delaware limited partnership. Magellan GP, LLC, a Delaware limited liability company, serves as our general partner and owns a 2% general partner interest in us. Magellan GP, LLC is a wholly-owned subsidiary of Magellan Midstream Holdings, L.P. (“MGG”), a publicly traded Delaware limited partnership. We and Magellan GP, LLC have contracted with Magellan Midstream Holdings GP, LLC (“MGG GP”), MGG’s general partner, to provide all general and administrative services (“G&A”) and operating functions required for our operations.

We operate and report in three business segments: the petroleum products pipeline system, the petroleum products terminals and the ammonia pipeline system. Our reportable segments offer different products and services and are managed separately because each requires different marketing strategies and business knowledge.

In the opinion of management, our accompanying consolidated financial statements, which are unaudited except for the consolidated balance sheet as of December 31, 2005, which is derived from audited financial statements, include all normal and recurring adjustments necessary to present fairly our financial position as of September 30, 2006, and the results of operations for the three and nine months ended September 30, 2005 and 2006 and cash flows for the nine months ended September 30, 2005 and 2006. The results of operations for the three and nine months ended September 30, 2006 are not necessarily indicative of the results to be expected for the full year ending December 31, 2006.

Pursuant to the rules and regulations of the Securities and Exchange Commission, the financial statements do not include all of the information and notes normally included with financial statements prepared in accordance with accounting principles generally accepted in the United States. These financial statements should be read in conjunction with the audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2005.

2. Allocation of Net Income

The allocation of net income between our general partner and limited partners for purposes of calculating net income per limited partner unit, follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2006	2005	2006
Net income	$ 40,758	$ 30,593	$ 121,849	$ 136,276
Direct charges to the general partner:				
Reimbursable G&A costs	1,049	(31)	2,693	934
Previously indemnified environmental charges	6,055	8,323	6,692	8,381
Total direct charges to general partner	7,104	8,292	9,385	9,315
Income before direct charges to general partner	47,862	38,885	131,234	145,591
General partner's share of distributions (a)	22.40%	27.13%	19.87%	27.08%
General partner's allocated share of net income before direct charges	10,719	10,550	26,077	39,428
Direct charges to general partner	7,104	8,292	9,385	9,315
Net income allocated to general partner	$ 3,615	$ 2,258	$ 16,692	$ 30,113
Net income	$ 40,758	$ 30,593	$ 121,849	$ 136,276
Less: net income allocated to general partner	3,615	2,258	16,692	30,113
Net income allocated to limited partners	$ 37,143	$ 28,335	$ 105,157	$ 106,163

(a) Under the "two class" method of computing earnings per unit, as prescribed by Statement of Financial Accounting Standards No. 128, "Earnings Per Share", when our distributions for any quarterly period are less than net income, we allocate earnings for that period based on a theoretical distribution model which assumes total distributions are equal to net income. For periods where distributions exceed net income, we allocate net income to the general and limited partners based on the proportion of their contractually-determined cash distributions declared and paid following the close of each quarter. Because second quarter 2006 distributions were less than our net income, we allocated net income based on a theoretical distribution of $0.61178 per unit, resulting in our general partner being allocated 28.3% of net income for that period. As noted above, our general partner's 27.08% share of distributions for the nine months ended September 30, 2006 is derived from its share of actual first and third quarter 2006 distributions plus its share of theoretical distributions for second quarter 2006.

Reimbursable G&A costs represent G&A expenses charged against our income during each respective period for which we either have been or will be reimbursed by our general partner under the terms of the new omnibus agreement (see Note 6 – Related Party Transactions). Consequently, these amounts have been charged directly against our general partner's allocation of net income. We record these reimbursements by our general partner as capital contributions. During 2004, we and our general partner entered into an agreement with a former affiliate to settle its indemnification obligations to us (see Note 12—Commitments and Contingencies). Following this settlement, the expenses associated with these previously indemnified costs have been charged directly to our general partner. We believe we will collect the full amount of the indemnification settlement and accordingly will continue to allocate amounts associated with previously indemnified costs to our general partner.

3. Comprehensive Income

A reconciliation of net income to comprehensive income is provided in the table below (in thousands). For information on our derivative instruments, see Note 11 – Derivative Financial Instruments.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	**2006**	**2005**	**2006**
Net income	$ 40,758	$ 30,593	$121,849	$136,276
Change in fair value of cash flow hedges	—	338	—	(648)
Amortization of net loss on cash flow hedges	53	53	158	158
Other comprehensive income (loss)	53	391	158	(490)
Comprehensive income	$ 40,811	$ 30,984	$122,007	$135,786

4. Asset Impairment

In June 2006, we recorded a $3.0 million charge against the earnings of our petroleum products pipeline system segment associated with an impairment of our Menard, Illinois terminal, which we may close in 2007. The impairment charge is included in operating expenses on our consolidated statements of income and the tables included in our segment disclosures note below. An impairment review was initiated during our review of second quarter results, which included management's reassessment of the system integrity costs that we would be required to incur on this terminal and the various probabilities of continuing to operate or close the facility. The carrying value of the Menard, Illinois terminal prior to the impairment was $3.6 million. The fair value of the terminal was determined using probability-weighted discounted cash flow techniques.

5. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different marketing strategies and business knowledge.

The non-generally accepted accounting principles measure of operating margin (in the aggregate and by segment) is presented in the following tables. The components of operating margin are computed by using amounts that are determined in accordance with generally accepted accounting principles ("GAAP"). A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the tables below. Management believes that investors benefit from having access to the same financial measures management uses to evaluate performance. Operating margin is an important measure of the economic performance of our core operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources between segments. Operating profit, alternatively, includes expense items, such as depreciation and amortization and affiliate G&A costs, that management does not consider when evaluating the core profitability of an operation.

	Three Months Ended September 30, 2005 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 103,307	$ 25,358	$ 3,745	$ (763)	$ 131,647
Product sales revenues	180,165	2,514	—	(550)	182,129
Affiliate management fee revenue	167	—	—	—	167
Total revenues	283,639	27,872	3,745	(1,313)	313,943
Operating expenses	52,836	9,838	2,197	(1,492)	63,379
Environmental	4,420	1,620	902	—	6,942
Product purchases	160,362	816	—	(678)	160,500
Equity earnings	(909)	—	—	—	(909)
Operating margin	66,930	15,598	646	857	84,031
Depreciation and amortization	9,550	3,897	194	857	14,498
Affiliate G&A	11,586	3,673	525	—	15,784
Operating profit	$ 45,794	$ 8,028	$ (73)	$ —	$ 53,749

	Three Months Ended September 30, 2006 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 111,139	$ 30,900	$ 3,517	$ (854)	$ 144,702
Product sales revenues	166,452	5,310	—	—	171,762
Affiliate management fee revenue	173	—	—	—	173
Total revenues	277,764	36,210	3,517	(854)	316,637
Operating expenses	49,649	11,289	3,211	(1,620)	62,529
Environmental	7,574	(4)	952	—	8,522
Product purchases	167,275	2,595	—	(129)	169,741
Equity earnings	(814)	—	—	—	(814)
Operating margin	54,080	22,330	(646)	895	76,659
Depreciation and amortization	9,400	4,687	200	895	15,182
Affiliate G&A	12,161	4,325	556	—	17,042
Operating profit	$ 32,519	$ 13,318	$ (1,402)	$ —	$ 44,435

	Nine Months Ended September 30, 2005 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 286,406	$ 76,374	$ 9,952	$ (2,460)	$ 370,272
Product sales revenues	449,124	8,925	—	(960)	457,089
Affiliate management fee revenue	501	—	—	—	501
Total revenues	736,031	85,299	9,952	(3,420)	827,862
Operating expenses	129,710	28,659	5,611	(4,546)	159,434
Environmental	6,950	1,710	1,254	—	9,914
Product purchases	412,009	3,491	—	(1,341)	414,159
Equity earnings	(2,231)	—	—	—	(2,231)
Operating margin	189,593	51,439	3,087	2,467	246,586
Depreciation and amortization	27,018	11,356	558	2,467	41,399
Affiliate G&A	33,495	10,950	1,599	—	46,044
Segment profit	$ 129,080	$ 29,133	$ 930	$ —	$ 159,143

	Nine Months Ended September 30, 2006 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 307,713	$ 96,642	$ 11,666	$ (2,573)	$ 413,448
Product sales revenues	478,841	14,623	—	—	493,464
Affiliate management fee revenue	518	—	—	—	518
Total revenues	787,072	111,265	11,666	(2,573)	907,430
Operating expenses	129,367	35,963	7,745	(4,855)	168,220
Environmental	9,488	122	1,651	—	11,261
Product purchases	450,291	8,288	—	(386)	458,193
Equity earnings	(2,479)	—	—	—	(2,479)
Operating margin	200,405	66,892	2,270	2,668	272,235
Depreciation and amortization	28,567	13,924	580	2,668	45,739
Affiliate G&A	34,132	12,027	1,647	—	47,806
Segment profit	$ 137,706	$ 40,941	$ 43	$ —	$ 178,690

6. Related Party Transactions

Affiliate Entity Transactions

In March 2004, we acquired a 50% ownership interest in Osage Pipe Line Company, LLC (“Osage Pipeline”). We are paid a management fee for operating the Osage pipeline. Management fees from operating the Osage pipeline, which we reported as affiliate management fee revenues, were $0.2 million for both the three months ended September 30, 2005 and 2006 and $0.5 million for both the nine months ended September 30, 2005 and 2006.

The following table summarizes affiliate costs and expenses that are reflected in the accompanying consolidated statements of income (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2006	2005	2006
MGG—allocated operating expenses	$ 17,017	—	$ 49,269	—
MGG—allocated G&A expenses	15,784	—	46,044	—
MGG GP—allocated operating expenses	—	18,234	—	54,316
MGG GP—allocated G&A expenses	—	17,042	—	47,806

In June 2003, we and our general partner entered into a services agreement with MGG pursuant to which MGG agreed to provide the employees necessary to conduct our operations. We reimbursed MGG for all payroll and benefit costs it incurred through December 24, 2005. On December 24, 2005, the employees necessary to conduct our operations were transferred to MGG GP, the services agreement with MGG was terminated and a new services agreement with MGG GP was executed. Consequently, we now reimburse MGG GP for costs of employees necessary to conduct our operations. The affiliate payroll and benefits accrual associated with this agreement at December 31, 2005 and September 30, 2006 was $17.0 million and $9.7 million, respectively. The long-term affiliate pension and benefits accruals associated with this agreement at December 31, 2005 and September 30, 2006 were $9.8 million and $11.4 million, respectively. We settle our affiliate payroll, payroll-related expenses and post-retirement benefit costs with MGG GP on a monthly basis and we settle our long-term pension liabilities through contributions to MGG GP's pension funds.

In June 2003, we and our general partner entered into an agreement with MGG whereby MGG agreed to reimburse us for G&A expenses (excluding equity-based compensation) in excess of a G&A cap as defined in the omnibus agreement. This agreement expires December 31, 2010. The amount of G&A costs that either has been or will be reimbursed by MGG to us was $1.0 million and $2.7 million for the three and nine months ended September 30, 2005, respectively, and $0.9 million for the nine months ended September 30, 2006. Our G&A expenses for the three months ended September 30, 2006 were below the cap and we will not receive any reimbursement from MGG for G&A expenses related to this quarter.

During 2004, we settled environmental indemnifications owed to us by a former affiliate. In addition, when MGG purchased our general partner interest in June 2003, it agreed to assume obligations for $21.9 million of our environmental liabilities. See Note 12—Commitments and Contingencies for additional information relative to these matters.

Other Related Party Transactions

MGG, which owns our general partner, is partially owned by an affiliate of Carlyle/Riverstone Global Energy and Power Fund II, L.P. ("CRF"). As of September 30, 2006, two of the members of our general partner's eight-member board of directors were nominees of CRF. The board of directors of our general partner has adopted a Board of Directors Conflict of Interest Policy and Procedure. In compliance with this policy, CRF has adopted procedures internally to assure that our proprietary and confidential information is protected from disclosure to competing companies in which CRF owns an interest. As part of these procedures, none of the nominees of CRF will serve on our general partner's board of directors and on the boards of directors of competing companies in which CRF owns an interest.

On January 25, 2005, affiliates of CRF acquired general and limited partner interests in SemGroup, L.P. ("SemGroup"). CRF's combined general and limited partner interests in SemGroup are approximately 30%. One of the members of the seven-member board of directors of SemGroup's general partner is a nominee of CRF, with three votes on that board. We are a party to a number of transactions with SemGroup and its affiliates. A summary of these transactions is provided in the following table (in millions):

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2006	Period From January 25, 2005 Through September 30, 2005	Nine Months Ended September 30, 2006
Product sales revenues	$ 35.3	$ 39.0	$ 86.2	$ 100.1
Product purchases	12.2	10.9	45.7	31.7
Terminalling and other services revenues	1.6	0.7	4.2	3.7
Storage tank lease revenues	0.8	0.8	2.0	2.5
Storage tank lease expense	0.3	0.3	0.8	0.8

In addition to the above, we provide common carrier transportation services to SemGroup. As of December 31, 2005 and September 30, 2006, we had recognized a receivable of $6.2 million and $6.4 million, respectively, from and a payable of $6.1 million and $0.8 million, respectively, to SemGroup and its affiliates. The receivable is included with the accounts receivable amounts and the payable is included with the accounts payable amounts on our consolidated balance sheets.

In February 2006, we signed an agreement with an affiliate of SemGroup under which we agreed to construct two 200,000 barrel tanks on our property at El Dorado, Kansas, to sell these tanks to SemGroup's affiliate and to lease these tanks back for a 10-year period. Through September 30, 2006, we have received $4.5 million associated with this transaction from SemGroup's affiliate, which we reported as prepaid construction costs from related party on our consolidated statements of cash flows.

CRF also has an ownership interest in the general partner of Buckeye Partners, L.P. ("Buckeye"). During the three months and nine months ended September 30, 2005, our operating expenses included $0.0 million and $0.3 million, respectively, of costs we incurred with Norco Pipe Line Company, LLC, which is a subsidiary of Buckeye. We have incurred no operating expenses with Buckeye or its subsidiaries during 2006.

During May 2005, John P. DesBarres was appointed as an independent director on our general partner's board of directors. Mr. DesBarres also serves as a board member for American Electric Power Company, Inc. ("AEPC") of Columbus, Ohio. During the three months ended September 30, 2005, and for the period May 1, 2005 through September 30, 2005, our operating expenses included $0.7 million and $1.1 million, respectively, of costs that we incurred with Public Service Company of Oklahoma ("PSO"), a subsidiary of AEPC. During the three and nine months ended September 30, 2006, our operating expenses included $0.8 million and $2.3 million, respectively, of costs we incurred with PSO.

Because our distributions have exceeded target levels as specified in our partnership agreement, our general partner receives 50% of any incremental cash distributed per limited partner unit. As of September 30, 2006, our executive officers collectively owned approximately 6% of MGG Midstream Holdings, L.P., the partial owner of MGG, which owns 100% of our general partner; consequently, our executive officers also indirectly benefit from these distributions. Assuming we have sufficient available cash to continue to pay distributions on all of our outstanding units for four quarters at our current quarterly distribution level of $0.59 per unit, our general partner would receive distributions of approximately $61.3 million on its combined 2% general partner interest and incentive distribution rights.

During February 2006, MGG sold 35% of its MGG limited partner units in an initial public offering. We did not receive any of the proceeds from MGG's initial public offering. Our ownership structure and operations have not been materially impacted by this transaction. In connection with the closing of this offering, we amended our partnership agreement to remove the requirements for our general partner to maintain its current 2% general partner interest in any future offering of our limited partner units. In addition, we amended our partnership agreement to restore the incentive distribution rights to the same level as before an amendment made in connection with our October 2004 pipeline system acquisition, which reduced the incentive cash distributions paid to our general partner by $1.3 million for 2004, $5.0 million for 2005 and $3.0 million for 2006. In return, MGG made a capital contribution to us on February 9, 2006 equal to $4.2 million, which represented the present value of the remaining reductions in our general partner's incentive cash distributions.

7. Inventory

Inventory at December 31, 2005 and September 30, 2006 was as follows (in thousands):

	December 31, 2005	September 30, 2006
Refined petroleum products	$ 56,680	$ 41,413
Natural gas liquids	9,693	34,058
Transmix	9,589	12,934
Additives	1,805	3,189
Other	388	371
Total inventory	$ 78,155	$ 91,965

8. Equity Investment

We use the equity method to account for our 50% ownership interest in Osage Pipeline. The remaining 50% interest is owned by National Cooperative Refining Association ("NCRA"). Our agreement with NCRA calls for equal sharing of Osage Pipeline's net income. Summarized financial information for Osage Pipeline for the three and nine months ended September 30, 2005 and 2006 is presented below (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2006	2005	2006
Revenues	$ 3,685	$ 3,736	$ 9,020	$10,890
Net income	$ 2,150	$ 1,960	$ 5,458	$ 5,955

Condensed balance sheets for Osage Pipeline as of December 31, 2005 and September 30, 2006 are presented below (in thousands):

	December 31, 2005	September 30, 2006
Current assets	$ 4,767	$ 5,074
Noncurrent assets	$ 4,535	$ 4,415
Current liabilities	$ 431	$ 814
Members' equity	$ 8,871	$ 8,675

A summary of our equity investment in Osage Pipeline is as follows (in thousands):

	Nine Months Ended September 30,	
	2005	2006
Equity investment at beginning of period	$ 25,084	$ 24,888
Equity earnings:		
Proportionate share of Osage earnings	2,729	2,977
Amortization of excess investment	(498)	(498)
Net equity earnings	2,231	2,479
Cash distributions	(2,150)	(3,075)
Equity investment at end of period	$ 25,165	$ 24,292

Our initial investment in Osage Pipeline included an excess net investment amount of $21.7 million, which is being amortized over the average asset lives of Osage Pipeline. Excess investment is the amount by which our initial investment exceeded our proportionate share of the book value of the net assets of the investment and represents additional value of the underlying identifiable assets. The unamortized excess net investment amount at December 31, 2005 and September 30, 2006, was $20.5 million and $20.0 million, respectively.

9. Employee Benefit Plans

MGG GP sponsors a pension plan for union employees, a pension plan for non-union employees and a post-retirement benefit plan for selected employees. The following tables present our consolidated net periodic benefit costs related to these plans during the three and nine months ended September 30, 2005 and 2006 (in thousands):

	Three Months Ended September 30, 2005		Nine Months Ended September 30, 2005	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of Net Periodic Benefit Costs:				
Service cost	$ 618	$ 225	$ 3,161	$ 397
Interest cost	405	374	1,400	746
Expected return on plan assets	(537)	—	(1,439)	—
Amortization of prior service cost	170	450	508	1,349
Amortization of actuarial loss	19	431	19	431
Net periodic benefit cost	$ 675	$ 1,480	$ 3,649	$ 2,923

	Three Months Ended September 30, 2006		Nine Months Ended September 30, 2006	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of Net Periodic Benefit Costs:				
Service cost	$ 1,397	$ 72	$ 4,191	$ 352
Interest cost	552	86	1,655	626
Expected return on plan assets	(476)	—	(1,429)	—
Amortization of prior service cost (credit)	169	(766)	508	133
Amortization of actuarial loss	134	275	403	506
Net periodic benefit cost	$ 1,776	$ (333)	$ 5,328	$ 1,617

10. Debt

Debt at December 31, 2005 and September 30, 2006 was as follows (in thousands):

	December 31, 2005	September 30, 2006
Magellan Pipeline notes:		
Current portion	$ 14,345	$ 14,345
Long-term portion	270,074	270,611
Total Magellan Pipeline notes	284,419	284,956
Revolving credit facility	13,000	33,500
6.45% Notes due 2014	249,546	249,579
5.65% Notes due 2016	250,019	248,543
Total debt	$ 796,984	$ 816,578

Magellan Pipeline Notes. During October 2002, Magellan Pipeline Company, L.P. ("Magellan Pipeline") entered into a private placement debt agreement with a group of financial institutions for $302.0 million of fixed-rate notes. The maturity date of the notes is October 7, 2007; however, we made scheduled payments on these notes of $15.1 million on October 7, 2005 and $14.3 million on October 7, 2006. The outstanding principal amount of the notes at December 31, 2005 and September 30, 2006 was decreased by $2.5 million and $1.9 million, respectively, for the change in the fair value of the associated hedge (see Note 11–Derivative Financial Instruments). The interest rate of the notes is fixed at 7.7%. However, including the impact of the associated fair value hedge, which effectively swaps $250.0 million of the fixed-rate notes to floating-rate debt, the weighted-average interest rate for the notes at September 30, 2005 and September 30, 2006 was 7.7% and 8.7%, respectively. We make deposits in an escrow account in anticipation of semi-annual interest payments on these notes and the cash deposits are secured; however, the notes themselves are unsecured. These deposits of $5.5 million at December 31, 2005 and $11.2 million at September 30, 2006 were reflected as restricted cash on our consolidated balance sheets.

Revolving Credit Facility. Our revolving credit facility has a borrowing capacity of $400.0 million, with a maturity date of May 25, 2011. The interest rate on the revolver is LIBOR plus a spread ranging from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. Borrowings under this revolving credit facility are unsecured. There was $33.5 million outstanding on the revolver at September 30, 2006. The net proceeds from the revolving credit facility were used for general corporate purposes, including capital expenditures. At both December 31, 2005 and September 30, 2006, $1.1 million of the facility was obligated for letters of credit, which is not reflected as debt on our consolidated balance sheets**.** The weighted-average interest rate on the revolver at December 31, 2005 and September 30, 2006 was 5.1% and 5.8%, respectively. A commitment fee is assessed at a rate from 0.05% to 0.125% depending on our credit rating.

6.45% Notes due 2014. On May 25, 2004, we sold $250.0 million aggregate principal of 6.45% notes due June 1, 2014 in an underwritten public offering. The notes were issued for the discounted price of 99.8%, or $249.5 million, and the discount is being accreted over the life of the notes. Including the impact of the amortization of the realized gains on the interest hedges associated with these notes (see Note 11–Derivative Financial Instruments), the effective interest rate of these notes is 6.3%. Interest is payable semi-annually in arrears on June 1 and December 1 of each year.

5.65% Notes due 2016. On October 15, 2004, we issued $250.0 million aggregate principal of 5.65% notes due 2016. The notes were issued for the discounted price of 99.9%, or $249.7 million, and the discount is being accreted over the life of the notes. Including the impact of hedges associated with these notes (see Note 11–Derivative Financial Instruments), the weighted-average interest rate of these notes at September 30, 2005 and 2006 was 5.6% and 6.0%, respectively. Interest is payable semi-annually in arrears on April 15 and October 15 of each year. The outstanding principal amount of the notes at December 31, 2005 and September 30, 2006 was increased by $0.3 million and decreased by $1.2 million, respectively, for the change in the fair value of the associated hedge.

11. Derivative Financial Instruments

We use interest rate derivatives to help us manage interest rate risk. The following table summarizes hedges we have settled associated with various debt offerings (dollars in millions):

Hedge	Date	Gain/(Loss) on Settlement Date	Amortization Period
Interest rate hedge...............................	October 2002	$ (1.0)	5-year life of Magellan Pipeline notes
Interest rate swaps and treasury lock ..	May 2004	5.1	10-year life of 6.45% notes
Interest rate swaps	October 2004	(6.3)	12-year life of 5.65% notes

In addition to the above, we have entered into the following interest rate swap agreements:

- During May 2004, we entered into certain interest rate swap agreements to hedge against changes in the fair value of a portion of the Magellan Pipeline senior notes. We have accounted for these interest rate hedges as fair value hedges. The notional amounts of the interest rate swap agreements total $250.0 million. Under the terms of the interest rate swap agreements, we receive 7.7% (the weighted-average interest rate of the outstanding Magellan Pipeline senior notes) and pay LIBOR plus 3.4%.

These hedges effectively convert $250.0 million of our fixed-rate debt to floating-rate debt. The interest rate swap agreements began on May 25, 2004 and expire on October 7, 2007, the maturity date of the Magellan Pipeline senior notes. Payments settle in April and October each year with LIBOR set in arrears. During each settlement period, we record the impact of this swap based on our best estimate of LIBOR. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR result in an adjustment to our interest expense. A 0.25% change in LIBOR would result in an annual adjustment to our interest expense associated with this hedge of $0.6 million. The fair value of the instruments associated with this hedge at December 31, 2005 and September 30, 2006 was $(2.5) million and $(1.9) million, respectively, which was recorded to other deferred liabilities and long-term debt.

- In October 2004, we entered into an interest rate swap agreement to hedge against changes in the fair value of a portion of the $250.0 million of senior notes due 2016 which were issued in October 2004. We have accounted for this interest rate hedge as a fair value hedge. The notional amount of this agreement is $100.0 million and effectively converts $100.0 million of our 5.65% fixed-rate senior notes issued in October 2004 to floating-rate debt. Under the terms of the agreement, we receive the 5.65% fixed rate of the notes and pay LIBOR plus 0.6%. The agreement began on October 15, 2004 and terminates on October 15, 2016, which is the maturity date of these notes. Payments settle in April and October each year with LIBOR set in arrears. During each settlement period we will record the impact of this swap based on our best estimate of LIBOR. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to our interest expense. A 0.25% change in LIBOR would result in an annual adjustment to our interest expense of $0.3 million associated with this hedge. The fair value of this hedge at December 31, 2005 and September 30, 2006, was $0.3 million and $(1.2) million, respectively, which was recorded to other noncurrent assets and long-term debt at December 31, 2005 and deferred liabilities and long-term debt at September 30, 2006.

- In September 2006, we entered into $125.0 million of forward starting interest rate swap agreements to hedge against variability of future interest payments on a portion of the debt we anticipate issuing no later than October 2007. Proceeds of the anticipated debt issuance will be used to refinance the Magellan Pipeline notes, which mature in October 2007. The agreements have a 30-year term, which matches the expected tenor of the anticipated debt. Under the terms of the agreements, we will receive a variable rate equal to three-month LIBOR and pay a fixed rate of 5.3%. The effective date of the agreements is October 9, 2007, at which time the agreements require a mandatory cash settlement. We have accounted for these agreements as cash flow hedges. The fair value of these agreements at September 30, 2006, was $(0.6) million, which was recorded to other deferred liabilities and other comprehensive income.

In February 2006, we entered into a forward sales contract for 0.1 million barrels of gasoline related to our petroleum products blending activities. Concurrent with that transaction, we entered into three derivative swap contracts to hedge against price changes associated with the sale of that product, in which we agreed to buy 0.1 million barrels of gasoline at the Platts average price in September 2006 and to sell 0.1 million barrels of gasoline at the fixed price of $77.28 per barrel. Our objective in entering into these derivatives was to lock in a gross margin on the expected sale. These derivative contracts were settled in September 2006. We realized a gain of $0.7 million on these derivatives, which we recorded as a reduction to product purchases costs.

12. Commitments and Contingencies

Estimated liabilities for environmental costs were $58.2 million and $59.3 million at December 31, 2005 and September 30, 2006, respectively. Environmental liabilities have been classified as current or noncurrent based on scheduled payments for certain of our environmental liabilities and management’s estimates regarding the timing of actual payments for all other environmental liabilities. Management estimates that expenditures associated with these environmental remediation liabilities will be paid over the next ten years.

During the third quarter of 2006, we entered into an agreement with a contractor pursuant to which the contractor assumed the responsibility for the remediation of certain of our environmental sites in exchange for $14.0 million to be paid over the next 10 years. We adjusted our environmental liabilities associated with these sites to the discounted amount of the cash payments to be made to this contractor as the amount and timing of cash payments to be made are reliably determinable. Further, we recognized expense for certain retroactive premiums paid, all of which resulted in a $5.1 million charge to environmental expenses during third-quarter 2006. The liability estimates for all of our other environmental sites are provided on an undiscounted basis.

Our environmental liabilities, among other items, include accruals associated with the *Environmental Protection Agency ("EPA") Issue, Kansas City, Kansas Release and Independence, Kansas Release*, which are discussed as follows:

EPA Issue. In July 2001, the EPA, pursuant to Section 308 of the Clean Water Act (the "Act") served an information request to a former affiliate with regard to petroleum discharges from its pipeline operations. That inquiry primarily focused on Magellan Pipeline, which we subsequently acquired. The response to the EPA's information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the U.S. Department of Justice ("DOJ") that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumes that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those releases may have also violated the Spill Prevention Control and Countermeasure requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these releases if the EPA were to successfully seek and obtain injunctive relief. We responded to the March 2004 information request in a timely manner and have entered into an agreement that provides both parties an opportunity to negotiate a settlement prior to initiating litigation. This matter was included in our May 2004 indemnification settlement (see *Indemnification Settlement* discussion below). We have accrued an amount for this matter based on our best estimates that is less than $22.0 million. Due to the uncertainties described above, it is reasonably possible that the amounts we have recorded for this environmental liability could change in the near term. Management is unable to determine with any accuracy what those amounts could be and they could be material to our results of operations and cash flows.

Kansas City, Kansas Release. During the second quarter of 2005, we experienced a line break and release of approximately 2,900 barrels of product on our petroleum products pipeline near our Kansas City, Kansas terminal. As of September 30, 2006, we have estimated remediation costs associated with this release of approximately $2.8 million. Through September 30, 2006, we have spent $1.9 million on remediation associated with this release and, as of September 30, 2006, have recorded associated environmental liabilities of $0.9 million. We have recognized a receivable of $1.2 million from our insurance carrier for this matter. The EPA has included this release with the 32 other releases discussed in *EPA Issue* above in negotiating any penalties or other injunctive relief that might be assessed.

Independence, Kansas Release. During the first quarter of 2006, we experienced a line break and release of approximately 3,200 barrels of product on our petroleum products pipeline near Independence, Kansas. As of September 30, 2006, we have estimated remediation costs associated with this release of approximately $5.0 million. Through September 30, 2006, we have spent $2.8 million on remediation associated with this release and, as of September 30, 2006, have recorded associated environmental liabilities of $2.2 million and a receivable of $3.5 million from our insurance carrier. The EPA has included this release with the 32 other releases discussed in *EPA Issue* above in negotiating any penalties or other injunctive relief that might be assessed.

Indemnification Settlement. Prior to May 2004, The Williams Companies, Inc. ("Williams") had agreed to indemnify us against certain environmental losses, among other things, associated with assets contributed to us at the time of our initial public offering or which we subsequently acquired from Williams. In May 2004, our general partner entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release Williams from these indemnifications. We received $35.0 million, $27.5 million and $20.0 million on July 1, 2004, 2005 and 2006, respectively, pursuant to this agreement, and we expect to receive a final installment payment of $35.0 million on July 1, 2007. While the settlement agreement releases Williams from its environmental and certain indemnifications, other indemnifications remain in effect. These remaining indemnifications cover issues involving employee benefits matters, rights of way, easements and real property, including asset titles, and unlimited losses and damages related to tax liabilities.

As of December 31, 2005 and September 30, 2006, known liabilities that would have been covered by Williams' previous indemnity agreements were $43.1 million and $47.1 million, respectively. Through September

30, 2006, we have spent $26.6 million of the $117.5 million indemnification settlement amount for indemnified matters, including $10.3 million of capital costs. The cash we have received from the indemnity settlement is not reserved and has been used for our various other cash needs, including expansion capital spending.

MGG Indemnification Obligation. Concurrent with its acquisition of limited and general partner interests in us, MGG agreed to assume obligations for $21.9 million of our environmental liabilities. Through September 30, 2006, we have incurred $21.7 million of costs pursuant to this agreement. Recorded liabilities covered by this indemnification were $5.5 million and $0.2 million at December 31, 2005 and September 30, 2006, respectively.

Environmental Receivables. Concurrent with MGG's assumption of environmental obligations to us, as discussed in *MGG Indemnification Obligation* above, we recorded a receivable from MGG of $21.9 million. Our receivable balance with MGG at December 31, 2005 and September 30, 2006 was $6.7 million and $3.7 million, respectively. Receivables from insurance carriers related to environmental matters were $2.1 million and $6.0 million at December 31, 2005 and September 30, 2006, respectively.

Unrecognized product gains. Our operations generate product overages and shortages. When we experience net product losses, we recognize expense for those losses in the period in which they occur. When we experience net product gains we have product on hand for which we have no cost basis. Therefore, these overages are not recognized in our financial statements until the associated barrels are either sold or are used to offset product losses. The combined net unrecognized product overages for our operations had a market value of approximately $6.1 million as of September 30, 2006. However, the actual amounts we will recognize in future periods will depend on product prices at the time the associated barrels are either sold or used to offset future product losses.

Other. We are a party to various other claims, legal actions and complaints arising in the ordinary course of business. In the opinion of management, the ultimate resolution of these claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification arrangements will not have a material adverse effect on our future financial position, results of operations or cash flows.

13. Long-Term Incentive Plan

We have a long-term incentive plan for certain employees who perform services for us and directors of our general partner. The long-term incentive plan primarily consists of phantom units. The long-term incentive plan permits the grant of awards covering an aggregate of 1.4 million of our limited partner units. The compensation committee of our general partner's board of directors administers the long-term incentive plan.

We adopted Statement of Financial Accounting Standard ("SFAS") No. 123(R) on January 1, 2006 using the modified prospective application method, which required us to account for our equity-based incentive awards granted prior to January 1, 2006 using the fair value method as defined in SFAS No. 123 instead of our previous methodology of using the intrinsic value method as defined in Accounting Principles Bulletin ("APB") No. 25. Due to the structure of our award grants prior to January 1, 2006, we recognized compensation expense under APB No. 25 in much the same manner as that required under SFAS No. 123; therefore, the impact of the change from accounting for the award grants under APB No. 25 to SFAS No. 123 was insignificant to our results of operations, financial position and cash flows.

The long-term incentive awards, discussed below, that have been granted by our general partner's board of directors are subject to forfeiture if employment is terminated for any reason other than for retirement, death or disability prior to the vesting date. If an award recipient retires, dies or becomes disabled prior to the end of the vesting period, the recipient's grant will be prorated based upon the completed months of employment during the vesting period and the award will be paid at the end of the vesting period. The award grants do not have an early vesting feature except when there is a change in control of our general partner. There was no impact on our cash from operating or financing activities during the three and nine months ended September 30, 2006, associated with these awards.

- In February 2003, our general partner issued approximately 106,000 unit award grants pursuant to the long-term incentive plan. These units vested on December 31, 2005 and because we exceeded certain performance metrics, the actual number of units awarded with this grant totaled approximately 181,000. Our long-term incentive compensation accruals for the three and nine months ended September 30, 2005, assumed this payout amount.

- Following the change in control of our general partner in June 2003, the board of directors of our general partner made the following grants to certain employees who became dedicated to providing services to us:
  - In October 2003, our general partner issued approximately 21,000 unit grants pursuant to the long-term incentive plan. Of these awards, approximately 20,000 units vested during 2003 and 2004. The remaining units vested on July 31, 2005.
  - In January 2004, our general partner issued approximately 22,000 unit grants pursuant to the long-term incentive plan. Of these awards, approximately 11,000 units vested in 2004 and approximately 11,000 units vested on July 31, 2005.

- In February 2004, our general partner issued approximately 159,000 unit award grants pursuant to the long-term incentive plan. The actual number of units that will be awarded under this grant is based on the attainment of short-term and long-term performance metrics. The number of phantom units that could ultimately be issued under this award ranges from zero up to a total of 303,000, as adjusted for estimated forfeitures and retirements; however, the awards are also subject to personal and other performance components which could increase or decrease the number of units to be paid out by as much as 40%. The units will vest at the end of 2006. We have estimated the number of units that will be awarded under this grant to be approximately 299,000, the value of which on September 30, 2006 was $11.0 million. Unrecognized estimated compensation expense associated with these awards as of September 30, 2006 was $0.9 million.

- In February 2005, our general partner issued approximately 161,000 unit award grants pursuant to the long-term incentive plan. The actual number of units that will be awarded under this grant is based on the attainment of long-term performance metrics. The number of phantom units that could ultimately be issued under this award ranges from zero units up to a total of 308,000 as adjusted for estimated forfeitures and retirements; however, the awards are also subject to personal and other performance components which could increase or decrease the number of units to be paid out by as much as 20%. The units will vest at the end of 2007. We have estimated the number of units that will be awarded under this grant to be approximately 293,000, the value of which on September 30, 2006 was $10.8 million. Unrecognized estimated compensation expense associated with these awards as of September 30, 2006 was $4.5 million.

- During the nine months ended September 30, 2006, our general partner issued approximately 178,000 unit award grants pursuant to the long-term incentive plan. These awards are being accounted for as follows:
  - Approximately 139,000 are based on the attainment of long-term performance metrics. These units vest on December 31, 2008. The number of units that could ultimately vest under this component of the award ranges from zero to approximately 266,000 as adjusted for expected forfeitures and retirements. Upon vesting, these award grants must be paid out in units; therefore, we have accounted for these awards using the equity method. The weighted-average fair value of the awards on the grant date was $24.63 per unit, which was based on our unit price on the grant date less the present value of the estimated cash distributions on those units during the vesting period. During the third quarter of 2006, we revised our estimate of the number of units that will vest under this grant from 132,000 to 240,000. The unrecognized compensation expense associated with these awards as of September 30, 2006 was $4.7 million, which will be recognized over the next 27 months.
  - Approximately 35,000 are based on personal performance at the discretion of the compensation committee. These units vest December 31, 2008. The number of units that could ultimately vest under this component of the award ranges from zero to approximately 67,000 as adjusted for expected forfeitures and retirements. Because vesting criteria for these awards are partially based on conditions other than service, performance or market conditions, we have accounted for these awards using the liability method; consequently, the compensation expense we recognize is based on the period-end closing price of our units and the percentage of the service period completed at each period end. During the third quarter of 2006, we revised our estimate of the number of units that will vest from

33,000 to 60,000. The value of these awards at September 30, 2006 was $2.2 million, and the unrecognized estimated compensation cost on that date was $1.7 million.

- An additional 4,000 units have been issued with various vesting dates. We are using the equity method to account for most of these awards. The unrecognized compensation expense associated with these awards is approximately $0.1 million.

Our equity-based incentive compensation expense for the three and nine months ended September 30, 2005 and 2006 is summarized as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2005	2006	2005	2006
2003 awards	$ 764	$ —	$ 2,269	$ (86)
October 2003 awards	1	—	7	(3)
January 2004 awards	15	—	102	(4)
2004 awards	1,408	1,679	3,368	3,407
2005 awards	498	1,591	1,388	3,177
2006 awards	—	1,179	—	1,742
Total	$ 2,686	$ 4,449	$ 7,134	$ 8,233

14. Distributions

We paid the following distributions during 2005 and 2006 (in thousands, except per unit amounts):

Cash Distribution Payment Date	Per Unit Cash Distribution Amount	Cash Distributions Paid			
		Common Units	Subordinated Units	General Partner	Total
02/14/05	$ 0.45625	$ 26,390	$ 3,887	$ 5,201	$ 35,478
05/13/05	0.48000	29,127	2,726	6,778	38,631
08/12/05	0.49750	30,189	2,825	7,939	40,953
11/14/05	0.53125	32,236	3,018	10,178	45,432
Total	$ 1.96500	$ 117,942	$ 12,456	$ 30,096	$ 160,494
02/14/06	$ 0.55250	$ 33,526	$ 3,138	$ 12,839	$ 49,503
05/13/06	0.56500	37,494	—	13,668	51,162
08/14/06	0.57750	38,323	—	14,498	52,821
11/14/06 (a)	0.59000	39,153	—	15,327	54,480
Total	$ 2.28500	$ 148,496	$ 3,138	$ 56,332	$ 207,966

(a) Our general partner declared this cash distribution on October 26, 2006 to be paid on November 14, 2006 to unitholders of record at the close of business on November 7, 2006.

In February 2006, we amended our partnership agreement to restore the incentive distribution rights to the same level as before an amendment made in connection with our October 2004 pipeline system acquisition, which reduced the incentive distributions paid to our general partner by $1.3 million for 2004, $5.0 million for 2005 and $3.0 million for 2006. In return, MGG made a capital contribution to us on February 9, 2006 equal to the present value of the remaining reductions in incentive distributions, or $4.2 million.

15. Net Income Per Unit

The following table provides details of the basic and diluted net income per unit computations (in thousands, except per unit amounts):

	Three Months Ended September 30, 2005			Nine Months Ended September 30, 2005		
	Income (Numerator)	Units (Denominator)	Per Unit Amount	Income (Numerator)	Units (Denominator)	Per Unit Amount
Basic net income per limited partner unit	$ 37,143	66,361	$ 0.56	$ 105,157	66,361	$ 1.58
Effect of dilutive restricted unit grants	—	231	—	—	249	—
Diluted net income per limited partner unit	$ 37,143	66,592	$ 0.56	$ 105,157	66,610	$ 1.58

	Three Months Ended September 30, 2006			Nine Months Ended September 30, 2006		
	Income (Numerator)	Units (Denominator)	Per Unit Amount	Income (Numerator)	Units (Denominator)	Per Unit Amount
Basic net income per limited partner unit	$ 28,335	66,361	$ 0.43	$ 106,163	66,361	$ 1.60
Effect of dilutive restricted unit grants	—	283	—	—	176	—
Diluted net income per limited partner unit	$ 28,335	66,644	$ 0.43	$ 106,163	66,537	$ 1.60

Units reported as dilutive securities are related to phantom unit grants (see Note 13 – Long-Term Incentive Plan).

16. Subsequent Events

On October 26, 2006, our general partner's board of directors declared a distribution of $0.59 per limited partner unit to be paid on November 14, 2006 to unitholders of record as of November 7, 2006.

On October 25, 2006, we experienced a line break and release of approximately 4,400 barrels of anhydrous ammonia on our ammonia pipeline near Clay Center, Kansas. We are in the process of estimating the repair and remediation costs associated with this release. We have insurance coverage for this incident with a deductible of $1.5 million. We are unable to estimate with any degree of certainty what penalties, if any, might be assessed by governmental agencies associated with this release which would not be covered by our insurance policy. Our net cost for repair and remediation plus any penalties that may be assessed could be material to our results of operations or cash flows.

On October 24, 2006, Jim H. Derryberry resigned from our board of directors and compensation committee. Mr. Derryberry was a non-management director recommended by CRF, which has recommended a replacement candidate for consideration by our board.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

We are a publicly traded limited partnership formed to own, operate and acquire a diversified portfolio of complementary energy assets. We are principally engaged in the transportation, storage and distribution of refined petroleum products. As of September 30, 2006, our three operating segments include:

- petroleum products pipeline system, which is primarily comprised of our 8,500-mile petroleum products pipeline system, including 45 terminals;
- petroleum products terminals, which principally includes our seven marine terminal facilities and 29 inland terminals; and
- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

The following discussion provides an analysis of the results for each of our operating segments, an overview of our liquidity and capital resources and other items related to our company. The following discussion and analysis should be read in conjunction with (i) our accompanying interim consolidated financial statements and related notes and (ii) our consolidated financial statements, related notes and management's discussion and analysis of financial condition and results of operations included in our Annual Report on Form 10-K for the year ended December 31, 2005.

Recent Developments

Distribution. On October 26, 2006, the board of directors of our general partner declared a quarterly cash distribution of $0.59 per unit for the period of July 1 through September 30, 2006, representing 22 consecutive quarterly distribution increases since our initial public offering in February 2001. The quarterly distribution will be paid on November 14, 2006 to unitholders of record on November 7, 2006.

Ammonia Pipeline Release. On October 25, 2006, we experienced a line break and release of approximately 4,400 barrels of anhydrous ammonia on our ammonia pipeline near Clay Center, Kansas. We are in the process of estimating the repair and remediation costs associated with this release. We have insurance coverage for this incident with a deductible of $1.5 million. We are unable to estimate with any degree of certainty what penalties, if any, might be assessed by governmental agencies associated with this release which would not be covered by our insurance policy. Our net cost for repair and remediation plus any penalties that may be assessed could be material to our results of operations or cash flows.

Director Resignation. On October 24, 2006, Jim H. Derryberry resigned from our board of directors and compensation committee. Mr. Derryberry was a non-management director recommended by Carlyle/Riverstone Global Energy and Power Fund II, L.P. ("CRF"), which has recommended a replacement candidate for consideration by our board.

Results of Operations

We believe that investors benefit from having access to the same financial measures being utilized by management. Operating margin, which is presented in the tables below, is an important measure used by management to evaluate the economic performance of our operations. This measure forms the basis of our internal financial reporting and is used by management in deciding how to allocate capital resources between segments. Operating margin is not a generally accepted accounting principles ("GAAP") measure, but the components of operating margin are computed by using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is also included in the tables below. Operating profit includes expense items, such as depreciation and amortization and affiliate general and administrative ("G&A") costs, which management does not consider when evaluating the core profitability of an operation.

Three Months Ended September 30, 2005 Compared to Three Months Ended September 30, 2006

	Three Months Ended September 30, 2005	Three Months Ended September 30, 2006	Variance Favorable (Unfavorable) $ Change	Variance Favorable (Unfavorable) % Change
Financial Highlights ($ in millions)				
Revenues:				
Transportation and terminals revenues:				
Petroleum products pipeline system	$ 103.3	$ 111.2	$ 7.9	8
Petroleum products terminals	25.4	30.9	5.5	22
Ammonia pipeline system	3.7	3.5	(0.2)	(5)
Intersegment eliminations	(0.8)	(0.9)	(0.1)	(13)
Total transportation and terminals revenues	131.6	144.7	13.1	10
Product sales	182.1	171.7	(10.4)	(6)
Affiliate management fees	0.2	0.2	—	—
Total revenues	313.9	316.6	2.7	1
Operating and environmental expenses:				
Petroleum products pipeline system	57.2	57.3	(0.1)	—
Petroleum products terminals	11.5	11.3	0.2	2
Ammonia pipeline system	3.1	4.2	(1.1)	(35)
Intersegment eliminations	(1.5)	(1.7)	0.2	13
Total operating and environmental expenses	70.3	71.1	(0.8)	(1)
Product purchases	160.5	169.7	(9.2)	(6)
Equity earnings	(0.9)	(0.8)	(0.1)	(11)
Operating margin	84.0	76.6	(7.4)	(9)
Depreciation and amortization expense	14.5	15.2	(0.7)	(5)
Affiliate G&A expense	15.8	17.0	(1.2)	(8)
Operating profit	$ 53.7	$ 44.4	$ (9.3)	(17)
Operating Statistics				
Petroleum products pipeline system:				
Transportation revenue per barrel shipped	$1.053	$1.052		
Transportation barrels shipped (million barrels)	79.4	84.5		
Petroleum products terminals:				
Marine terminal facilities:				
Average storage capacity utilized per month (million barrels)[(a)]	18.6	18.8		
Inland terminals:				
Throughput (million barrels)	28.6	31.7		
Ammonia pipeline system:				
Volume shipped (thousand tons)	149	159		

(a) For the three months ended September 30, 2005, represents the average storage capacity utilized for the one month we owned our Wilmington, Delaware facility (1.8 million barrels) and the average storage capacity utilized for the full quarter at our other marine terminals (16.8 million barrels).

The $13.1 million increase in transportation and terminals revenues primarily resulted from:

- a $7.9 million increase in petroleum products pipeline system revenues primarily related to higher gasoline and diesel fuel volume shipments during the current period, principally reflecting increased demand from our customers. Increased ancillary fees for additive services and leased storage further benefited the current quarter; and

- a $5.5 million increase in petroleum products terminals revenues. Revenues increased at our marine terminals due to operating results from our Wilmington, Delaware marine terminal, which we acquired in

September 2005, and expansion projects completed over the past year as well as higher rates due to strong demand at our other marine terminals. Our inland terminal revenues also increased due to record throughput volumes and higher additive fees.

The $0.8 million increase in operating and environmental expenses was primarily due to increases in our ammonia pipeline system. Operating and environmental expenses for our petroleum products pipeline system increased by only $0.1 million due to offsetting events. Discussion of these items are as follows:

- a $0.1 million increase in petroleum products pipeline system expenses primarily because higher system integrity spending and higher environmental expenses were mostly offset by lower charges for asset retirements and lower product losses in the current quarter. Our environmental expenses increased $2.8 million primarily due to our entering an agreement in the third quarter of 2006 pursuant to which a contractor assumed the responsibility for the remediation of certain of our environmental sites in exchange for $14.0 million to be paid out over the next 10 years. We entered into this agreement to mitigate our future financial exposure relative to certain known environmental locations. We adjusted our environmental liabilities to the discounted amount of the cash payments to be made to this contractor. Further, we recognized expense for certain risk and retroactive insurance premiums paid, all of which resulted in a $5.1 million charge to environmental expense during third-quarter 2006; and

- a $1.1 million increase in ammonia pipeline system expenses primarily attributable to higher system integrity costs. We expect the amount of system integrity spending for our ammonia pipeline system to be significantly higher during 2006 and 2007 due to the timing of high consequence area testing mandated by federal regulations.

Product sales revenues primarily result from a third-party product supply agreement, our petroleum products blending operations and transmix fractionation. Revenues from product sales were $171.7 million for the three months ended September 30, 2006, while product purchases were $169.7 million, resulting in gross margin from these transactions of $2.0 million. The gross margin resulting from product sales and purchases for the 2006 period decreased $19.6 million compared to gross margin for the 2005 period of $21.6 million, reflecting product sales for the three months ended September 30, 2005 of $182.1 million and product purchases of $160.5 million. The 2006 period was negatively impacted by lower product supply agreement and fractionation margins as a result of rapidly declining gasoline and diesel fuel prices during third-quarter 2006. These lower product prices resulted in us recognizing a lower-of-cost-or-market adjustment of $8.4 million in the current quarter. As we have previously disclosed, the gross margin we realize on these activities can be substantially higher in periods when refined petroleum product prices increase and substantially lower in periods when product prices decline or stabilize given that we follow an average inventory valuation methodology which results in each period’s product purchases being influenced by the value of products held in that period’s beginning inventory.

Operating margin decreased $7.4 million between periods primarily due to lower commodity margin principally attributable to declining petroleum product prices in the current period partially offset by improved performance of our petroleum products pipeline system and terminals assets.

The $0.7 million increase in depreciation and amortization expense is primarily related to asset acquisitions and capital improvements over the past year.

The $1.2 million increase in affiliate G&A expenses is primarily related to our equity-based incentive compensation program, which impacted G&A expenses by $3.8 million during the 2006 period and $2.2 million during the 2005 period. The higher compensation expense resulted from the increase in our unit price during the current period and increases in the number of units management estimates will vest under our equity-based incentive compensation program. Excluding equity-based incentive compensation expense, the amount of cash we spend for G&A costs is determined by an agreement we have with Magellan Midstream Holdings, L.P. (“MGG”), the owner of our general partner. For the three months ended September 30, 2006 and 2005, we were responsible for paying cash G&A costs of $13.2 million and $12.6 million, respectively. MGG reimburses us for our actual G&A costs that exceed these amounts, excluding equity-based incentive compensation expense. The amount of G&A reimbursed to us was zero for the 2006 quarter, as our actual costs were below the cap amount, and $1.0 million for the 2005 quarter.

Interest expense, net of capitalized interest, was $13.6 million for the three months ended September 30, 2006, compared to $13.5 million for the three months ended September 30, 2005, for an increase of $0.1 million. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $808.3 million during third-quarter 2006 from $802.0 million during third-quarter 2005 primarily due to borrowings under our revolving credit facility to fund our capital spending and working capital needs. Further, the weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, increased to 7.0% for the 2006 period from 6.6% for the 2005 period primarily due to rising interest rates. Increases in interest expense were offset by higher capitalized interest in the current period associated with our increased capital spending program.

Interest income for the three months ended September 30, 2006 was $0.5 million compared to $1.3 million for the three months ended September 30, 2005, a decline of $0.8 million, primarily due to lower cash balances in the current period. We have been utilizing available cash to fund our increased expansion capital projects, resulting in lower cash balances for financial investment.

Net income for the three months ended September 30, 2006 was $30.6 million compared to $40.8 million for the three months ended September 30, 2005, a decrease of $10.2 million, or 25%.

Nine Months Ended September 30, 2005 Compared to Nine Months Ended September 30, 2006

	Nine Months Ended September 30,		Variance	
			Favorable (Unfavorable)	
	2005	2006	$ Change	% Change
Financial Highlights ($ in millions)				
Revenues:				
Transportation and terminals revenues:				
Petroleum products pipeline system	$ 286.4	$ 307.7	$ 21.3	7
Petroleum products terminals	76.4	96.6	20.2	26
Ammonia pipeline system	10.0	11.7	1.7	17
Intersegment eliminations	(2.5)	(2.5)	—	—
Total transportation and terminals revenues	370.3	413.5	43.2	12
Product sales	457.1	493.4	36.3	8
Affiliate management fees	0.5	0.5	—	—
Total revenues	827.9	907.4	79.5	10
Operating and environmental expenses:				
Petroleum products pipeline system	136.6	138.9	(2.3)	(2)
Petroleum products terminals	30.4	36.1	(5.7)	(19)
Ammonia pipeline system	6.9	9.4	(2.5)	(36)
Intersegment eliminations	(4.6)	(4.9)	0.3	7
Total operating and environmental expenses	169.3	179.5	(10.2)	(6)
Product purchases	414.2	458.2	(44.0)	(11)
Equity earnings	(2.2)	(2.5)	0.3	14
Operating margin	246.6	272.2	25.6	10
Depreciation and amortization expense	41.4	45.7	(4.3)	(10)
Affiliate G&A expense	46.1	47.8	(1.7)	(4)
Operating profit	$ 159.1	$ 178.7	$ 19.6	12
Operating Statistics				
Petroleum products pipeline system:				
Transportation revenue per barrel shipped	$1.035	$1.053		
Transportation barrels shipped (million barrels)	222.0	231.4		
Petroleum products terminals:				
Marine terminal facilities:				
Average storage capacity utilized per month (million barrels)[a]	18.5	18.9		
Inland terminals:				
Throughput (million barrels)	83.6	89.7		
Ammonia pipeline system:				
Volume shipped (thousand tons)	487	537		

(a) For the nine months ended September 30, 2005, represents the average storage capacity utilized for the one month we owned our Wilmington, Delaware facility (1.8 million barrels) and the average storage capacity utilized for the nine-month period at our other marine terminals (16.8 million barrels).

Transportation and terminals revenues increased by $43.2 million as a result of:

- an increase in petroleum products pipeline system revenues of $21.3 million primarily related to increased diesel fuel and gasoline shipments during the current period, as a result of increased demand from our customers, and an increase in the average transportation rate per barrel shipped. We also earned more ancillary revenues related to additive and terminal services during 2006;

- an increase in petroleum products terminals revenues of $20.2 million primarily due to results from our Wilmington, Delaware marine terminal, which we acquired in September 2005, and the recognition of revenue during first-quarter 2006 related to a variable-rate storage agreement. Under this variable-rate storage agreement we provided storage rental and throughput fees based on discounted rates plus a variable fee, which was based on a percentage of the net profits from certain trading activities conducted by our customer. During 2006, we recognized revenues of $6.4 million from the variable fee portion of the agreement once our customer's trading profits were determinable at the end of the contract term, which expired January 31, 2006. Upon expiration of this agreement, we negotiated a similar agreement pursuant to which we will receive a share of any net trading profits above a specified amount, but we will not share in any net trading losses. Until the agreement expires on December 31, 2006, we will not know the actual amount of revenues we will recognize. However, based on customer activity to date, the results from this variable-rate storage agreement could result in us recognizing additional storage revenues in excess of $2.0 million during fourth-quarter 2006. Revenues also increased at our inland terminals due to higher additive fees and throughput volumes and at our marine terminals primarily due to higher rates and expansion projects completed over the past year; and

- an increase in ammonia pipeline system revenues of $1.7 million due to higher tariffs associated with our new transportation agreements, which became effective July 1, 2005, and increased volumes.

The $10.2 million increase in operating and environmental expenses was principally the result of:

- an increase in petroleum products pipeline system expenses of $2.3 million. Expenses were higher in 2006 primarily due to power costs, property taxes and personnel expenses as well as additional environmental expenses. Our environmental expenses increased primarily due to our entering an agreement in the third quarter of 2006 pursuant to which a contractor assumed the responsibility for the remediation of certain of our environmental sites in exchange for $14.0 million to be paid out over the next 10 years. We entered into this agreement to mitigate our future financial exposure relative to certain known environmental locations. We adjusted our environmental liabilities to the discounted amount of the cash payments to be made to this contractor. Further, we recognized expense for certain risk and retroactive insurance premiums paid. These increases were partially offset by more favorable product overages in the current period due to higher commodity prices and sales of accumulated system overages, which reduce operating expenses;

- an increase in petroleum products terminals expenses of $5.7 million. This increase was primarily related to expenses associated with our Wilmington marine terminal, which we acquired in September 2005, and higher power and personnel costs at our other terminals; and

- an increase in ammonia pipeline system expenses of $2.5 million, primarily attributable to higher power costs, increased environmental expenses and additional system integrity costs. We expect the amount of system integrity spending to be significantly higher during 2006 and 2007 due to the timing of high consequence area testing mandated by federal regulations.

Product sales revenues primarily result from a third-party product supply agreement, our petroleum products blending operations and transmix fractionation. Revenues from product sales were $493.4 million for the nine months ended September 30, 2006, while product purchases were $458.2 million, resulting in gross margin from these transactions of $35.2 million. The gross margin resulting from product sales and purchases for the 2006 period decreased $7.7 million compared to gross margin for the 2005 period of $42.9 million, reflecting product sales for the nine months ended September 30, 2005 of $457.1 million and product purchases of $414.2 million. The 2006 period was negatively impacted by lower product supply agreement and fractionation margins as a result of rapidly declining gasoline and diesel fuel prices during third-quarter 2006, partially offset by higher blending volumes and margins. The lower product prices resulted in us recognizing a lower-of-cost-or-market adjustment of $8.4 million in the current period. As we have previously disclosed, the gross margin we realize on these activities can be substantially higher in periods when refined petroleum product prices increase and substantially lower in periods when product prices decline or stabilize given that we follow an average inventory valuation methodology which results in each period's product purchases being influenced by the value of products held in that period's beginning inventory.

Operating margin increased $25.6 million primarily due to revenues from a variable-rate terminalling agreement, incremental operating results from our recently-acquired Wilmington marine facility and improved utilization of our assets.

Depreciation and amortization expense increased by $4.3 million. This increase is primarily related to asset acquisitions and capital improvements over the past year and the acceleration of depreciation for our terminal automation systems that we are in the process of upgrading.

Affiliate G&A expenses increased by $1.7 million. This increase is primarily related to our equity-based compensation program, which impacted G&A expenses by $7.0 million during the 2006 period and $5.9 million during the 2005 period. The higher compensation expense resulted from the increase in our unit price during the current period and increases in the number of units management estimates will vest under our equity-based incentive compensation program. G&A expenses were also higher during 2006 due to higher annual bonus accruals. Excluding equity-based incentive compensation expense, the amount of cash we spend for G&A costs is determined by an agreement we have with MGG. For the nine months ended September 30, 2006 and 2005, we were responsible for paying G&A costs of $39.9 million and $37.5 million, respectively. MGG reimburses us for our actual G&A costs that exceed these amounts, excluding equity-based incentive compensation expense. The amount of G&A reimbursed to us for the nine months ended September 30, 2006 and 2005 was $0.9 million and $2.7 million, respectively.

Interest expense, net of capitalized interest, was $41.8 million for the nine months ended September 30, 2006 compared to $38.8 million for the nine months ended September 30, 2005, for an increase of $3.0 million, or 8%. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $807.4 million during the nine-month period ended September 30, 2006 from $802.0 million during the nine-month period ended September 30, 2005 primarily due to borrowings under our revolving credit facility to fund our capital spending and working capital needs. Further, the weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, increased to 7.0% for the 2006 period from 6.4% for the 2005 period primarily due to rising interest rates. Additionally, capitalized interest in 2006 was $0.7 million higher than in 2005.

Interest income for the nine months ended September 30, 2006 was $1.7 million compared to $3.4 million for the nine months ended September 30, 2005, a decline of $1.7 million, primarily as a result of lower cash balances. We have been utilizing available cash to fund our increased expansion capital projects, resulting in lower cash balances for financial investment.

Net income for the nine months ended September 30, 2006 was $136.3 million compared to $121.9 million for the nine months ended September 30, 2005, an increase of $14.4 million, or 12%.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $164.0 million and $196.8 million for the nine months ended September 30, 2006 and 2005, respectively. The $32.8 million decrease from 2005 to 2006 was primarily attributable to:

- an increase in accounts receivable and other accounts receivable of $12.6 million. During 2005, we received a cash payment of $27.5 million related to an indemnification settlement. Of the amount received, $10.1 million related to amounts previously recorded as other accounts receivable and the collection of that receivable balance was reflected as cash from operating activities during the 2005 period. The remaining $17.4 million of the $27.5 million payment and all subsequent indemnification settlement payments were accounted for as affiliate capital contributions and were classified as cash from financing activities;

- changes in inventory values resulted in a decrease in cash from operating activities of $13.9 million. Reduction in inventories increased cash from operating activities by $0.1 million in the 2005 period, while an increase in inventories decreased cash from operating activities by $13.8 million in the 2006 period. The increase in inventories for the 2006 period is primarily due to a build of butane inventories, partially offset by lower product prices at the end of the current quarter; and

- a decrease in accrued product purchases of $13.0 million in 2006 compared to an increase of $1.7 million in 2005, which resulted in a $14.7 million decrease in cash from operating activities between the periods. The decrease is primarily due to the timing of invoices received from our suppliers.

These decreases were partially offset by increased net income of $14.4 million.

Net cash used by investing activities for the nine months ended September 30, 2006 and 2005 was $99.8 million and $30.0 million, respectively. During 2006, we spent $105.6 million for capital expenditures versus $118.0 million in 2005, including $55.3 million for the acquisition of our Wilmington, Delaware marine terminal. Of these amounts, total maintenance capital spending before indemnifications and reimbursements was $20.9 million and $17.7 million during the nine months ended September 30, 2006 and 2005, respectively. In 2005, our sales of marketable securities, net of purchases, generated $87.8 million of cash. Please see Capital Requirements below for further discussion of capital expenditures as well as maintenance capital amounts net of indemnifications.

Net cash used by financing activities for the nine months ended September 30, 2006 and 2005 was $100.6 million and $96.0 million, respectively, and primarily consisted of cash distributions paid to our unitholders. During 2006, net borrowings on our revolving credit facility of $20.5 million and capital contributions from our general partner of $25.7 million partially offset distribution payments. The capital contributions received in the 2006 period included $4.2 million received from MGG as part of our agreement to restore the incentive distribution rights to the same level as before an amendment made in connection with our October 2004 pipeline system acquisition, $20.0 million from the environmental indemnification settlement payment received in July 2006 and the remainder from contributions for our G&A expenses over the cap. Capital contributions for 2005 included $17.4 million from the environmental indemnification settlement payment received in July 2005 ($27.5 million received less $10.1 million of amounts previously recorded as accounts receivable) with the remainder attributable to amounts received for G&A costs in excess of the cap.

During third-quarter 2006, we paid $52.8 million in cash distributions to our unitholders and general partner. Based on the declared quarterly distribution of $0.59 per unit associated with the third quarter of 2006, we intend to pay $54.5 million in distributions during fourth quarter 2006. If we continue to pay cash distributions at this current level and the number of outstanding units remains the same, we will pay total cash distributions of $217.9 million on an annual basis. Of this amount, $61.3 million, or 28%, is related to our general partner's 2% ownership interest and incentive distribution rights.

Capital Requirements

Our businesses require continual investment to upgrade or enhance existing operations and to ensure compliance with safety and environmental regulations. Capital spending for our businesses consists primarily of:

- maintenance capital expenditures, such as those required to maintain equipment reliability and safety and to address environmental regulations; and

- expansion capital expenditures to acquire additional complementary assets to grow our business and to expand or upgrade our existing facilities, referred to as organic growth projects. Organic growth projects include capital expenditures that increase storage or throughput volumes or develop pipeline connections to new supply sources.

During third-quarter 2006, we spent maintenance capital of $6.8 million, excluding $1.9 million of spending that would have been covered by indemnifications settled in May 2004. For the nine months ended September 30, 2006, we have spent maintenance capital of $17.5 million, excluding $3.4 million of spending that would have been covered by the indemnifications settled in May 2004. Including the $20.0 million payment we received on July 1, 2006, we have received $82.5 million to date under this settlement agreement. Please see Environmental below for additional discussion of this indemnification settlement.

For 2006, we expect to incur maintenance capital expenditures for our existing businesses of approximately $30.0 million, excluding $6.0 million for environmental projects that would have been covered by the indemnifications discussed above.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities. For the three and nine months ended September 30, 2006, we spent cash of $29.9 million and $84.8 million, respectively, for organic growth projects. Based on projects currently underway or in advanced stages of development, we currently plan to spend approximately $140.0 million on organic growth capital during 2006, excluding future acquisitions, and approximately $115.0 million collectively during 2007 and 2008 to complete these projects.

Liquidity

As of September 30, 2006, total debt reported on our consolidated balance sheet was $816.6 million, as described below. The difference between this amount and the $820.4 million face value of our outstanding debt is due to adjustments associated with fair value hedges.

Magellan Pipeline Notes. In connection with the long-term financing of our acquisition of Magellan Pipeline Company, L.P. ("Magellan Pipeline"), we and Magellan Pipeline entered into a note purchase agreement on October 1, 2002. As of September 30, 2006, $286.9 million of senior notes were outstanding pursuant to this agreement. The maturity date of these notes is October 7, 2007, with a scheduled prepayment equal to 5% of the outstanding balance made on October 7, 2006. We guarantee payment of interest and principal by Magellan Pipeline. The notes are unsecured except for cash deposited monthly by Magellan Pipeline into a cash escrow account in anticipation of semi-annual interest payments. The weighted-average interest rate for the senior notes, including the impact of the swap of $250.0 million of the notes from fixed-rate to floating-rate debt, was 8.7% at September 30, 2006.

Revolving Credit Facility. In May 2006, we amended and restated our revolving credit facility to increase the borrowing capacity of the facility from $175.0 million to $400.0 million. In addition, the maturity of the facility was extended to May 2011, and the interest rate on borrowings under the facility was reduced from LIBOR plus a spread ranging from 0.6% to 1.5% based on our credit ratings to LIBOR plus a spread that ranges from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. Borrowings under this credit facility remain unsecured. As of September 30, 2006, $33.5 million was outstanding under this facility, and $1.1 million of the facility was obligated for letters of credit. The obligations for letters of credit are not reflected as debt on our consolidated balance sheets. As of September 30, 2006, the weighted-average interest rate on borrowings outstanding under this facility was 5.8%.

6.45% Senior Notes due 2014. On May 25, 2004, we sold $250.0 million of 6.45% senior notes due 2014 in an underwritten public offering at 99.8% of par. We received proceeds after underwriters' fees and expenses of approximately $246.9 million. Including the impact of pre-issuance hedges associated with these notes, the effective interest rate on these notes at September 30, 2006 was 6.3%.

5.65% Senior Notes due 2016. On October 15, 2004, we sold $250.0 million of 5.65% senior notes due 2016 in an underwritten public offering as part of the long-term financing of the pipeline system assets we acquired in October 2004. The notes were issued at 99.9% of par, and we received proceeds after underwriters' fees and expenses of approximately $247.6 million. Including the impact of pre-issuance hedges associated with these notes and the swap of $100.0 million of the notes from fixed-rate to floating-rate, the weighted-average interest rate on the notes at September 30, 2006 was 6.0%.

The debt instruments described above include various covenants. In addition to certain financial ratio covenants, these covenants limit our ability to, among other things, incur indebtedness secured by certain liens, encumber our assets, make certain investments, engage in certain sale-leaseback transactions and consolidate, merge or dispose of all or substantially all of our assets. We are in compliance with these covenants.

Interest Rate Derivatives. We utilize interest rate derivatives to manage interest rate risk. We were engaged in the following interest-rate derivative transactions as of September 30, 2006:

- In September 2006, we entered into $125.0 million of forward starting interest rate swap agreements to hedge against variability of future interest payments on a portion of the debt we anticipate issuing no later than October 2007. Proceeds of the anticipated debt issuance will be used to refinance the Magellan Pipeline notes, which mature in October 2007. The interest rate swap agreements have a 30-year term, which matches the expected tenor of the anticipated debt. The effective date of the agreements is October 9, 2007, at which time the agreements require a mandatory cash settlement. The fixed rate provided in the agreements is 5.3%;

- In October 2004, we entered into a $100.0 million interest rate swap agreement to hedge against changes in the fair value of a portion of our 5.65% senior notes due 2016. This agreement effectively changes the interest rate on $100.0 million of those notes to a floating rate of six-month LIBOR plus 0.6%, with

LIBOR set in arrears. This swap agreement expires on October 15, 2016, the maturity date of the 5.65% senior notes; and

- In May 2004, we entered into $250.0 million of interest rate swap agreements to hedge against changes in the fair value of a portion of the Magellan Pipeline senior notes. These agreements effectively change the interest rate on $250.0 million of the senior notes from a fixed rate of 7.7% to a floating rate of six-month LIBOR plus 3.4%, with LIBOR set in arrears. These swap agreements expire on October 7, 2007, the maturity date of the Magellan Pipeline senior notes.

Credit Ratings. Our current credit ratings are BBB by Standard and Poor's and Baa3 by Moody's Investor Services.

Environmental

Various governmental authorities in the jurisdictions in which we conduct our operations subject us to environmental laws and regulations. We have accrued liabilities for estimated site restoration costs to be incurred in the future at our facilities and properties, including liabilities for environmental remediation obligations at various sites where we have been identified as a possible responsible party. Under our accounting policies, we record liabilities when site restoration and environmental remediation obligations are either known or considered probable and can be reasonably estimated. The determination of amounts recorded for environmental liabilities involve significant judgments and assumptions by management. Due to the inherent uncertainties involved in determining environmental liabilities, it is reasonably possible that the actual amounts required to extinguish these liabilities could be materially different from those we have recognized.

Prior to May 2004, The Williams Companies, Inc. ("Williams") provided indemnifications to us for assets we had acquired from it. In May 2004, we entered into an agreement with Williams under which Williams agreed to pay us $117.5 million to release it from those indemnification obligations. Including the $20.0 million payment we received from Williams on July 1, 2006, we have received $82.5 million pursuant to this agreement and expect to receive the remaining balance of $35.0 million on July 1, 2007. As of September 30, 2006, known liabilities that would have been covered by these indemnifications were $47.1 million. In addition, we have spent $26.6 million through September 30, 2006 that would have been covered by these indemnifications, including $10.3 million of capital costs. We have not reserved the cash received from this indemnity settlement but have used it for our various other cash needs, including expansion capital spending.

During the third quarter of 2006, we entered into an agreement with a contractor to mitigate against the risk of increases in certain of our existing environmental liabilities. The agreement requires that the contractor assume responsibility for the environmental remediation of certain sites and purchase cost cap insurance from an insurance company. We are an additional named insured under that policy, and were required to pay the related insurance premium. In connection with this agreement, we increased the related environmental liabilities by $2.9 million, to equal the discounted value of the cash payments to be made to the contractor pursuant to the agreement, and recorded $2.2 million of expense to reflect risk and insurance premiums paid for a total charge of $5.1 million in the current period.

When MGG purchased our general partner interest in June 2003, MGG assumed obligations to indemnify us for $21.9 million of known environmental liabilities. Through September 30, 2006, we have incurred $21.7 million of costs associated with this obligation, leaving a remaining indemnification obligation of $0.2 million. Our receivable balance with MGG related to these environmental indemnities was $3.7 million on September 30, 2006.

In July 2001, the Environmental Protection Agency ("EPA"), pursuant to Section 308 of the Clean Water Act (the "Act") served an information request to Williams with regard to petroleum discharges from its pipeline operations. That inquiry primarily focused on Magellan Pipeline, which we subsequently acquired in April 2002. The response to the EPA's information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the U.S. Department of Justice ("DOJ") that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumes that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those spills may have also violated the Spill Prevention Control and Countermeasure requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these releases if the EPA were to successfully seek and obtain injunctive relief. We responded to the March 2004 information request in a timely manner and have entered into an agreement that provides both parties an opportunity to negotiate a settlement prior to initiating litigation. We have accrued an amount that is less than $22.0 million associated with this matter. Due to the uncertainties described above, it is reasonably possible that the amounts we have recorded for this environmental liability could change in the near term. Management is unable to determine with any accuracy what those amounts could be and they could be material to our results of operations or cash flows.

Other Items

Pipeline tariff increase. The Federal Energy Regulatory Commission ("FERC") regulates the rates charged on interstate common carrier pipeline operations primarily through an index methodology, which establishes the maximum amount by which tariffs can be adjusted. The FERC reviews this approved methodology on a periodic basis. Until recently, the annual adjustment was equal to the annual change in the producer price index for finished goods ("PPI-FG"). During March 2006, the FERC approved the methodology of PPI-FG plus 1.3% for the annual adjustment related to the next five year period, commencing July 1, 2006. Based on an actual annual change in PPI-FG of approximately 4.8%, the 2006 mid-year adjustment resulted in an allowed increase on indexed tariffs of approximately 6.1%. We increased a significant majority of our published tariffs by approximately 6.1% effective July 1, 2006.

Galena Park marine terminal expansion. During late 2005 and early 2006, we executed a series of long-term terminalling agreements with several customers pursuant to which we will construct 30 new storage tanks at our Galena Park, Texas marine terminal. Tank construction has begun and we expect the new tanks to be placed into service at intervals during 2006, 2007 and 2008. We believe these new agreements will significantly contribute to our results of operations and cash flows once construction is complete and the 30 new tanks have been placed into service.

Unrecognized product gains. Our operations generate product overages and shortages. When we experience net product shortages, we recognize expense for those losses in the period in which they occur. When we experience product overages, we have product on hand for which we have no cost basis. Therefore, these overages are not recognized in our financial statements until the associated barrels are either sold or used to offset product losses. The net unrecognized product overages for our operations had a market value of approximately $6.1 million as of September 30, 2006. However, the actual amounts we will recognize in future periods will depend on product prices at the time the associated barrels are either sold or used to offset future product losses.

State tax issues. Texas legislators recently passed a law that, without amendment, will impose a partnership-level tax beginning in 2007 based on the financial results of our assets apportioned to the state of Texas. While we currently expect our tax obligation to be less than $3.0 million per year, this tax will impact the amount of cash available for us to pay as distributions to our unitholders. If other states create a similar tax, the impact could be material to our results of operations or cash flows.

Affiliate transactions. In June 2003, we and our general partner entered into a services agreement with MGG pursuant to which MGG agreed to provide the employees necessary to conduct our operations. We reimbursed MGG for all payroll and benefit costs it incurred through December 24, 2005. On December 24, 2005, the employees necessary to conduct our business operations were transferred to MGG's general partner, and the services agreement with MGG was terminated and a new services agreement with MGG's general partner was executed. Consequently, we now reimburse MGG's general partner for costs of employees necessary to conduct our operations. Also in June 2003, we and our general partner entered into an agreement with MGG whereby MGG agreed to reimburse us for G&A expenses, excluding equity-based compensation, in excess of a defined G&A cap.

For the three and nine month periods ended September 30, 2006, we were allocated operating expenses from MGG and its general partner of $18.2 million and $54.3 million, respectively, and G&A expenses of $17.0 million and $47.8 million, respectively. For the three and nine month periods ended September 30, 2005, we were allocated operating expenses from MGG and its general partner of $17.0 million and $49.3 million, respectively, and G&A expenses of $15.8 million and $46.0 million, respectively. MGG was not required to reimburse us for G&A costs during third quarter 2006 as our actual costs were below the cap amount but has reimbursed us $0.9 million for the nine months ended September 30, 2006. MGG reimbursed us G&A costs of $1.0 million and $2.7 million for the three and nine months ended September 30, 2005, respectively.

In March 2004, we acquired a 50% ownership interest in a crude oil pipeline company. We earn a fee to operate this pipeline which was $0.5 million for both the nine months ended September 30, 2006 and 2005. We report these fees as affiliate management fee revenue on our consolidated statements of income.

Related party transactions. MGG is partially owned by an affiliate of CRF. As of September 30, 2006, two members of our general partner's eight-member board of directors were nominees of CRF. The board of directors of our general partner has adopted a policy to address board of director conflicts of interests. In compliance with this policy, CRF has adopted procedures internally to assure that our proprietary and confidential information is protected from disclosure to competing companies in which CRF owns an interest. As part of these procedures, none of the nominees of CRF will serve on our general partner's board of directors and on the boards of directors of competing companies in which CRF owns an interest.

On January 25, 2005, affiliates of CRF acquired general and limited partner interests in SemGroup, L.P. ("SemGroup"). CRF's total combined general and limited partner interests in SemGroup are approximately 30%. One of the members of the seven-member board of directors of SemGroup's general partner is a nominee of CRF, with three votes on that board.

We are a party to a number of transactions with SemGroup and its affiliates. For the three and nine months ended September 30, 2006, we recognized revenues from SemGroup related to the sale of petroleum products of $39.0 million and $100.1 million, respectively; terminalling and other services of $0.7 million and $3.7 million, respectively; and leased storage tanks of $0.8 million and $2.5 million, respectively. For the three months ended September 30, 2005 and the period from January 25, 2005 through September 30, 2005, we recognized revenues from SemGroup related to the sale of petroleum products of $35.3 million and $86.2 million, respectively; terminalling and other services of $1.6 million and $4.2 million, respectively; and leased storage tanks of $0.8 million and $2.0 million, respectively. We also provide common carrier transportation services to SemGroup.

Additionally, during the three and nine months ended September 30, 2006, we recognized product purchases from SemGroup of $10.9 million and $31.7 million, respectively, and expenses for leased storage tanks of $0.3 million and $0.8 million, respectively. During the three months ended September 30, 2005 and the period from January 25, 2005 through September 30, 2005, we recognized product purchases from SemGroup of $12.2 million and $45.7 million, respectively, and expenses for leased storage tanks of $0.3 million and $0.8 million, respectively.

In February 2006, we signed an agreement with an affiliate of SemGroup under which we agreed to construct two 200,000 barrel tanks on our property at El Dorado, Kansas, to sell these tanks to SemGroup's affiliate and to lease these tanks back for a 10-year period. Through September 30, 2006, we have received $4.5 million associated with this transaction from SemGroup's affiliate, which we reported as prepaid construction costs from related party on our consolidated statements of cash flows. In conjunction with this agreement, we received a three-year throughput commitment from SemGroup.

As of September 30, 2006, we had recognized a receivable of $6.4 million from and a payable of $0.8 million to SemGroup and its affiliates.

During the second quarter of 2006, an affiliate of CRF announced that it, along with a group of other investors, made an offer to acquire Kinder Morgan, Inc. Among other assets, Kinder Morgan, Inc. owns the general partner interest of Kinder Morgan Energy Partners, L.P., a publicly traded partnership engaged in the transportation and distribution of petroleum products and natural gas that is a customer of ours and competes with us in various markets that we serve. Once this acquisition is complete, all transactions between us and Kinder Morgan, Inc. and its affiliates might become related party transactions.

CRF also has an ownership interest in the general partner of Buckeye Partners, L.P. ("Buckeye"). We do not have a significant relationship with Buckeye and do not have extensive operations in the geographic areas primarily served by Buckeye.

Because our distributions have exceeded target levels as specified in our partnership agreement, MGG indirectly receives 50% of any incremental cash distributed per limited partner unit. As of September 30, 2006, the executive officers of our general partner collectively owned approximately 6% of MGG Midstream Holdings, L.P., which owns 65% of MGG, and therefore also indirectly benefit from these distributions. Assuming MMP has sufficient available cash to continue to pay distributions on all of its outstanding units for four quarters at its current quarterly distribution level of $0.59 per unit, MGG would receive annual distributions of approximately $61.3 million on its combined 2% general partner interest and incentive distribution rights.

NEW ACCOUNTING PRONOUNCEMENTS

In September 2006, the Financial Accounting Standards Board ("FASB") adopted Statement of Financial Accounting Standards ("SFAS") No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*. The Statement requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. We estimate the impact of adopting this Statement to our consolidated balance sheets will be an increase to our long-term affiliate pension and benefits liabilities with an offsetting reduction to other comprehensive income of approximately $23.0 million at December 31, 2006. Our consolidated statements of income and cash flows will not be impacted from the adoption of this Statement.

In September, the FASB also adopted SFAS No. 157, *Fair Value Measurements*. This Statement defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value measurements. This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. This Statement will affect our disclosures but is not expected to have a material impact on our consolidated statements of income, balance sheets or cash flows.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We may be exposed to market risk through changes in commodity prices and interest rates. We have established policies to monitor and control these market risks. We also enter into derivative agreements to help manage our exposure to commodity price and interest rate risks.

As of September 30, 2006, we had $33.5 million outstanding on our variable rate revolving credit facility. We had no other variable rate debt outstanding; however, because of certain interest rate swap agreements discussed below, we are exposed to interest rate market risk on an additional $350.0 million of our debt. Considering these interest rate swap agreements and the amount outstanding on our revolving credit facility as of September 30, 2006, our annual interest expense would change by $1.0 million if LIBOR were to change by 0.25%.

During May 2004, we entered into four separate interest rate swap agreements to hedge against changes in the fair value of a portion of the Magellan Pipeline notes. We have accounted for these interest rate hedges as fair value hedges. The notional amounts of the interest rate swap agreements total $250.0 million. Under the terms of the agreements, we receive 7.7% (the interest rate on the Magellan Pipeline notes) and pay LIBOR plus 3.4%. These hedges effectively convert $250.0 million of our fixed-rate debt to floating-rate debt. The interest rate swap agreements began on May 25, 2004 and expire on October 7, 2007. Payments settle in April and October of each year with LIBOR set in arrears.

During October 2004, we entered into an interest rate swap agreement to hedge against changes in the fair value of a portion of the $250.0 million of senior notes due 2016. We have accounted for this interest rate hedge as a fair value hedge. The notional amount of the interest rate swap agreement is $100.0 million. Under the terms of the agreement, we receive 5.65% (the interest rate of the $250.0 million senior notes) and pay LIBOR plus 0.6%. This hedge effectively converts $100.0 million of our 5.65% fixed-rate debt to floating-rate debt. The interest rate swap agreement began on October 15, 2004 and expires on October 15, 2016. Payments settle in April and October of each year with LIBOR set in arrears.

In September 2006, we entered into $125.0 million of forward starting interest rate swap agreements to hedge against variability of future interest payments on a portion of the debt we anticipate issuing no later than October

2007. Proceeds of the anticipated debt issuance will be used to refinance the Magellan Pipeline notes, which mature in October 2007. The interest rate swap agreements have a 30-year term, which matches the expected tenor of the anticipated debt. The effective date of the agreements is October 9, 2007, at which time the agreements require a mandatory cash settlement. The fixed rate provided in the agreements is 5.3%.

As of September 30, 2006, we had entered into futures contracts, qualifying as normal purchases, for the purchase of approximately 0.2 million barrels of petroleum products. The notional value of these agreements, with maturities from October 2006 through November 2006, was approximately $11.5 million.

As of September 30, 2006, we had entered into futures contracts, qualifying as normal sales, for the sale of approximately 0.6 million barrels of petroleum products. The notional value of these agreements, with maturities from October 2006 through December 2006, was approximately $42.4 million.

ITEM 4. CONTROLS AND PROCEDURES

An evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rule 13a-14(c) of the Securities Exchange Act) was performed as of the end of the period covered by the date of this report. This evaluation was performed under the supervision and with the participation of our management, including our general partner's Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner's Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and practices are effective in providing reasonable assurance that all required disclosures are included in the current report.

Our management, including our general partner's Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls or our internal controls over financial reporting ("internal controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our disclosure controls and internal controls and make modifications as necessary; our intent in this regard is that the disclosure controls and the internal controls will be maintained as systems change and conditions warrant. There have been no substantial changes in our internal controls since December 31, 2005.

FORWARD-LOOKING STATEMENTS

Certain matters discussed in this Quarterly Report on Form 10-Q include forward-looking statements that discuss our expected future results based on current and pending business operations.

Forward-looking statements can be identified by words such as "anticipates," "believes," "expects," "estimates," "forecasts," "projects" and other similar expressions. Although we believe our forward-looking statements are based on reasonable assumptions, statements made regarding future results are subject to numerous assumptions, uncertainties and risks that may cause future results to be materially different from the results stated or implied in this document.

The following are among the important factors that could cause future results to differ materially from actual results or from any projected, forecasted, estimated or budgeted amounts which we have discussed in this report:

- price fluctuations for natural gas liquids and refined petroleum products;

- overall demand for natural gas liquids, refined petroleum products, natural gas, oil and ammonia in the United States;
- weather patterns materially different than historical trends;
- development of alternative energy sources;
- changes in demand for storage in our petroleum products terminals;
- changes in supply patterns for our marine terminals due to geopolitical events;
- our ability to manage interest rate and commodity price exposures;
- our ability to satisfy our product purchase obligations at historical purchase terms;
- changes in our tariff rates implemented by the Federal Energy Regulatory Commission, the United States Surface Transportation Board and state regulatory agencies;
- shut-downs or cutbacks at major refineries, petrochemical plants, ammonia production facilities or other businesses that use or supply our services;
- changes in the throughput or interruption in service on petroleum products pipelines owned and operated by third parties and connected to our petroleum products terminals or petroleum products pipeline system;
- loss of one or more of our three customers on our ammonia pipeline system;
- an increase in the competition our operations encounter;
- the occurrence of an operational hazard or unforeseen interruption for which we are not adequately insured;
- the treatment of us as a corporation for federal income tax purposes or if we become subject to entity-level taxation for state tax purposes;
- our ability to make and integrate acquisitions and successfully complete our business strategy;
- changes in general economic conditions in the United States;
- changes in laws or regulations to which we are subject, including tax withholding issues, safety, environmental and employment laws and regulations;
- the cost and effects of legal and administrative claims and proceedings against us or our subsidiaries;
- the amount of our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at competitive disadvantages compared to our competitors that have less debt or could have other adverse consequences;
- a change of control of our general partner could, under certain circumstances, result in our debt or the debt of our subsidiaries becoming due and payable;
- the condition of the capital markets in the United States;
- the effect of changes in accounting policies;
- the potential that internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful and the impact these could have on our unit price;

- the ability of third parties to pay the amounts owed to us under indemnification agreements;

- conflicts of interests between us, our general partner, MGG, MGG's general partner and related parties of MGG and its general partner;

- the ability of our general partner, its affiliates or related parties to enter into certain agreements which could negatively impact our financial position, results of operations and cash flows;

- supply disruption; and

- global and domestic economic repercussions from terrorist activities and the government's response thereto.

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In July 2001, the EPA pursuant to Section 308 of the Act served an information request to a former affiliate with regard to petroleum discharges from its pipeline operations. That inquiry primarily focused on Magellan Pipeline, which we subsequently acquired. The response to the EPA's information request was submitted during November 2001. In March 2004, we received an additional information request from the EPA and notice from the DOJ that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Section 311(b) of the Act in regards to 32 releases. The DOJ stated that the maximum statutory penalty for the releases was in excess of $22.0 million, which assumes that all releases are violations of the Act and that the EPA would impose the maximum penalty. The EPA further indicated that some of those releases may have also violated the Spill Prevention Control and Countermeasure requirements of Section 311(j) of the Act and that additional penalties may be assessed. In addition, we may incur additional costs associated with these releases if the EPA were to successfully seek and obtain injunctive relief. We responded to the March 2004 information request in a timely manner and have entered into an agreement that provides both parties an opportunity to negotiate a settlement prior to initiating litigation. We have accrued an amount for this matter based on our best estimates that is less than $22.0 million. Due to the uncertainties described above, it is reasonably possible that the amounts we have recorded for this environmental liability could change in the near term. Management is unable to determine with any accuracy what those amounts could be and they could be material to our results of operations and cash flows.

During the second quarter of 2005, we experienced a product release involving approximately 2,900 barrels of gasoline from our petroleum products pipeline near our Kansas City, Kansas terminal. In regards to this release, we responded on a timely basis to an EPA request for information pursuant to Section 308 of the Act. We can provide no assurances that we will not be assessed civil or other statutory penalties of $100,000 or more by the EPA or other regulatory agencies associated with this release.

During the first quarter of 2006, we experienced a product release involving approximately 3,200 barrels of gasoline from our petroleum products pipeline near Independence, Kansas. We can provide no assurances that we will not be assessed civil or other statutory penalties of $100,000 or more by the EPA or other regulatory agencies associated with this release.

We are a party to various legal actions that have arisen in the ordinary course of our business. We do not believe that the resolution of these matters will have a material adverse effect on our financial condition or results of operations.

ITEM 1A. RISK FACTORS

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2005, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not our only risks. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Exhibit 10.1*	–	Director Deferred Compensation Plan effective October 1, 2006 (filed as Exhibit 10.1 to Form 8-K filed October 4, 2006).
Exhibit 12.1	–	Ratio of earnings to fixed charges.
Exhibit 31.1	–	Rule 13a-14(a)/15d-14(a) Certification of Don R. Wellendorf, principal executive officer.
Exhibit 31.2	–	Rule 13a-14(a)/15d-14(a) Certification of John D. Chandler, principal financial and accounting officer.
Exhibit 32.1	–	Section 1350 Certification of Don R. Wellendorf, Chief Executive Officer.
Exhibit 32.2	–	Section 1350 Certification of John D. Chandler, Chief Financial Officer.

***** Exhibit has been previously filed with the Securities and Exchange Commission as part of the filing indicated and is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized in Tulsa, Oklahoma, on November 6, 2006.

MAGELLAN MIDSTREAM PARTNERS, L.P.

By: Magellan GP, LLC,
its General Partner

/s/ John D. Chandler
John D. Chandler
Chief Financial Officer
and Treasurer (Principal Accounting and Financial Officer)

INDEX TO EXHIBITS

EXHIBIT NUMBER	DESCRIPTION
10.1*	Director Deferred Compensation Plan effective October 1, 2006 (filed as Exhibit 10.1 to Form 8-K filed October 4, 2006).
12.1	Ratio of earnings to fixed charges.
31.1	Rule 13a-14(a)/15d-14(a) Certification of Don R. Wellendorf, principal executive officer.
31.2	Rule 13a-14(a)/15d-14(a) Certification of John D. Chandler, principal financial and accounting officer.
32.1	Section 1350 Certification of Don R. Wellendorf, Chief Executive Officer.
32.2	Section 1350 Certification of John D. Chandler, Chief Financial Officer.

* Exhibit has been previously filed with the Securities and Exchange Commission as part of the filing indicated and is incorporated herein by reference.

Exhibit 12.1

MAGELLAN MIDSTREAM PARTNERS, L.P.
RATIO OF EARNINGS TO FIXED CHARGES
(In thousands)

	Year Ended December 31,					Nine Months Ended September 30,
	2001	**2002**	**2003**	**2004**	**2005**	**2006**
EARNINGS:						
Income from continuing operations before income taxes, extraordinary gain (loss) and cumulative effect of change in accounting principle *	$ 97,613	$ 107,495	$ 88,169	$ 108,601	$ 156,379	$ 133,797
Fixed charges	15,755	33,344	39,779	41,657	56,656	45,478
Amortization of interest capitalized	465	471	462	463	465	356
Distributed income of equity investees	—	—	—	—	3,300	3,075
Interest capitalized	(764)	(231)	(102)	(426)	(817)	(1,448)
Total earnings	$ 113,069	$ 141,079	$ 128,308	$ 150,295	$ 215,983	$ 181,360
FIXED CHARGES:						
Interest expense	$ 15,370	$ 23,138	$ 36,699	$ 38,319	$ 53,371	$ 43,116
Debt expense amortization	253	9,950	2,830	3,056	2,871	2,034
Rent expense representative of interest factor	132	256	250	282	414	328
Total fixed charges	$ 15,755	$ 33,344	$ 39,779	$ 41,657	$ 56,656	$ 45,478
Ratio of earnings to fixed charges	7.2	4.2	3.2	3.6	3.8	4.0

* Excludes income from equity investments and minority interest expense.