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 June 30, 2007

OR

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

For the transition period from to

Commission File 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 (as defined in Rule 12-b-2 of the Exchange Act). Yes ☐ No ☒

As of August 3, 2007, there were outstanding 66,546,297 common units.

PART I
FINANCIAL INFORMATION

PART II
OTHER INFORMATION

MAGELLAN MIDSTREAM PARTNERS, L.P.
PART I
FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2007	2006	2007
Transportation and terminals revenues	$ 138,555	$ 150,070	$ 268,746	$ 293,221
Product sales revenues	172,806	177,902	321,702	326,565
Affiliate management fee revenue	172	183	345	356
Total revenues	311,533	328,155	590,793	620,142
Costs and expenses:				
Operating	55,045	60,027	108,430	121,002
Product purchases	154,857	156,588	288,452	290,568
Depreciation and amortization	15,356	15,695	30,557	31,135
Affiliate general and administrative	15,737	17,741	30,764	35,426
Total costs and expenses	240,995	250,051	458,203	478,131
Equity earnings	946	1,106	1,665	1,869
Operating profit	71,484	79,210	134,255	143,880
Interest expense	14,466	15,072	28,757	29,939
Interest income	(601)	(746)	(1,247)	(1,117)
Interest capitalized	(429)	(1,205)	(632)	(2,102)
Debt placement fee amortization	678	1,154	1,355	1,799
Debt prepayment premium	—	1,984	—	1,984
Other expense	—	699	339	699
Income before income taxes	57,370	62,252	105,683	112,678
Provision for income taxes	—	800	—	1,524
Net income	$ 57,370	$ 61,452	$ 105,683	$ 111,154
Allocation of net income for purposes of calculating earnings per limited partner unit:				
Limited partners' interest	$ 41,143	$ 43,790	$ 77,828	$ 80,641
General partner's interest	16,227	17,662	27,855	30,513
Net income	$ 57,370	$ 61,452	$ 105,683	$ 111,154
Basic net income per limited partner unit	$ 0.62	$ 0.66	$ 1.17	$ 1.21
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	66,361	66,549	66,361	66,543
Diluted net income per limited partner unit	$ 0.62	$ 0.66	$ 1.17	$ 1.21
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	66,482	66,549	66,482	66,547

See notes to consolidated financial statements.

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

	December 31, 2006	June 30, 2007
		(Unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6,390	$ 13,276
Restricted cash	5,283	—
Accounts receivable (less allowance for doubtful accounts of $51 and $31 at December 31, 2006 and June 30, 2007, respectively)	51,730	50,543
Other accounts receivable	13,288	13,954
Affiliate accounts receivable	483	308
Inventory	91,550	95,320
Other current assets	8,294	8,219
Total current assets	177,018	181,620
Property, plant and equipment	2,260,608	2,342,054
Less: accumulated depreciation	557,869	585,851
Net property, plant and equipment	1,702,739	1,756,203
Equity investments	24,087	23,631
Long-term receivables	6,920	6,699
Goodwill	23,945	23,945
Other intangibles (less accumulated amortization of $5,196 and $5,970 at December 31, 2006 and June 30, 2007, respectively)	8,633	7,859
Debt placement costs (less accumulated amortization of $9,592 and $1,827 at December 31, 2006 and June 30, 2007, respectively)	5,829	6,576
Other noncurrent assets	3,478	3,273
Total assets	$1,952,649	$2,009,806
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 55,549	$ 26,505
Affiliate accounts payable	11,008	10,713
Affiliate payroll and benefits	18,676	15,067
Accrued interest payable	9,266	7,835
Accrued taxes other than income	17,460	18,445
Environmental liabilities	34,952	35,360
Deferred revenue	22,901	21,878
Accrued product purchases	63,098	28,827
Current portion of long-term debt	270,839	—
Other current liabilities	14,640	11,544
Total current liabilities	518,389	176,174
Long-term debt	518,609	865,459
Long-term affiliate payable	8,133	1,273
Long-term affiliate pension and benefits	29,278	33,208
Other deferred liabilities	48,945	52,758
Environmental liabilities	22,813	25,615
Commitments and contingencies		
Partners' capital:		
Partners' capital	825,333	868,009
Accumulated other comprehensive loss	(18,851)	(12,690)
Total partners' capital	806,482	855,319
Total liabilities and partners' capital	$1,952,649	$2,009,806

See notes to consolidated financial statements.

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

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2007
Operating Activities:		
Net income	$ 105,683	$ 111,154
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	30,557	31,135
Debt placement fee amortization	1,355	1,799
Debt prepayment premium	—	1,984
Loss on sale and retirement of assets	4,674	4,333
Equity earnings	(1,665)	(1,869)
Distributions from equity investments	2,025	2,325
Equity method incentive compensation expense	412	1,261
Amortization of prior service cost and net actuarial loss	—	998
Changes in components of operating assets and liabilities:		
Accounts receivable and other accounts receivable	(9,571)	521
Affiliate accounts receivable	(486)	175
Inventory	(8,911)	(3,770)
Accounts payable	9,653	(18,628)
Affiliate accounts payable	2,610	(295)
Affiliate payroll and benefits	(4,327)	(3,609)
Accrued interest payable	(189)	(1,431)
Accrued taxes other than income	772	985
Accrued product purchases	(18,215)	(34,271)
Restricted cash	(14)	5,283
Current and noncurrent environmental liabilities	(4,329)	3,210
Other current and noncurrent assets and liabilities	101	3,417
Net cash provided by operating activities	110,135	104,707
Investing Activities:		
Property, plant and equipment:		
Additions to property, plant and equipment	(67,119)	(89,108)
Proceeds from sale of assets	540	950
Changes in accounts payable	—	(10,416)
Prepaid construction costs from related party	4,000	—
Net cash used by investing activities	(62,579)	(98,574)
Financing Activities:		
Distributions paid	(100,665)	(114,412)
Net borrowings under revolver	12,200	101,500
Borrowings under notes	—	248,900
Payments on notes	—	(272,555)
Debt placement costs	(383)	(2,546)
Payment of debt prepayment premium	—	(1,984)
Net receipt from financial derivatives	—	4,556
Capital contributions by affiliate	5,189	37,294
Other	16	—
Net cash provided (used) by financing activities	(83,643)	753
Change in cash and cash equivalents	(36,087)	6,886
Cash and cash equivalents at beginning of period	36,489	6,390
Cash and cash equivalents at end of period	$ 402	$ 13,276
Supplemental non-cash financing activity:		
Issuance of common units in settlement of 2004 long-term incentive plan awards	$ —	$ 7,406

See notes to consolidated financial statements.

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

1. Organization and Basis of Presentation and Other

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 an approximate 2% general partner interest in us as well as all of our incentive distribution rights. 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 (“G&A”) services 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, 2006, which is derived from audited financial statements, include all normal and recurring adjustments necessary to present fairly our financial position as of June 30, 2007, and the results of operations for the three and six months ended June 30, 2006 and 2007 and cash flows for the six months ended June 30, 2006 and 2007. The results of operations for the three and six months ended June 30, 2007 are not necessarily indicative of the results to be expected for the full year ending December 31, 2007.

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, 2006.

Other

Beginning in 2007, the state of Texas implemented a partnership-level tax based on a percentage of the financial results of our assets apportioned to the state of Texas. We have reported our estimate of this tax as provision for income taxes on our consolidated statements of income.

2. Allocation of Net Income

For purposes of calculating earnings per unit, the allocation of net income between our general partner and limited partners was as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2007	2006	2007
Allocation of net income to general partner:				
Net income	$ 57,370	$ 61,452	$ 105,683	$ 111,154
Direct charges to the general partner:				
Reimbursable G&A costs (a)	553	1,604	965	1,880
Previously indemnified environmental charges (b)	(542)	622	58	2,872
Total direct charges to general partner	11	2,226	1,023	4,752
Income before direct charges to general partner	57,381	63,678	106,706	115,906
General partner's share of income (c)	28.30%	31.23%	27.06%	30.43%
General partner's allocated share of net income before direct charges	16,238	19,888	28,878	35,265
Direct charges to general partner	(11)	(2,226)	(1,023)	(4,752)
Net income allocated to general partner	$ 16,227	$ 17,662	$ 27,855	$ 30,513
Net income	$ 57,370	$ 61,452	$ 105,683	$ 111,154
Less: net income allocated to general partner	16,227	17,662	27,855	30,513
Net income allocated to limited partners	$ 41,143	$ 43,790	$ 77,828	$ 80,641

(a) Reimbursable G&A costs for the three and six months ended June 30, 2007 include a $1.3 million non-cash expense related to a payment by MGG Midstream Holdings, L.P., an affiliate which owns MGG GP. Except for this $1.3 million non-cash expense, the reimbursable G&A costs above represent G&A expenses during the periods presented that were required to be reimbursed to us by MGG under the terms of an omnibus agreement to which MGG is a party. Because our limited partners do not share in these costs, we have allocated these G&A expense amounts directly to our general partner. We record these reimbursements as capital contributions from an affiliate.

(b) We and our general partner entered into an agreement with a former affiliate to settle certain of our former affiliate's indemnification obligations to us (see Note 12—Commitments and Contingencies). Under this agreement, our former affiliate agreed to pay us $117.5 million over a four-year period. On June 29, 2007, we received the final installment payment of $35.0 million. Following this settlement, the expenses associated with these previously indemnified costs have been allocated directly to our general partner.

(c) Under the "two class" method of computing earnings per unit, as prescribed by Statement of Financial Accounting Standards No. 128, "Earnings Per Share," earnings are allocated to participating securities as if all of the earnings for the period had been distributed. For periods when the distributions we pay exceed our net income, the general partner's percentage share of income is its proportion of cash distributions paid for the period. For periods when net income exceeds the cash distributions paid, the general partner's percentage share of income is its proportion of theoretical cash distributions that equal net income. For the second quarter of 2006 and 2007, a per unit theoretical cash distribution of $0.612 and $0.658, respectively, would have resulted in total distributions equal to net income for each period. At these distribution levels, the general partner's share of distributions would have been 28.30% and 31.23% for the second quarter of 2006 and 2007, respectively. The general partner's share of net income for computing earnings per unit for the six months ended June 30, 2006 and 2007 is based on its share of actual distributions paid for the first quarter of each respective year and the theoretical distributions for the second quarter of each respective year.

3. Comprehensive Income

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2007	2006	2007
Net income	$ 57,370	$ 61,452	$105,683	$111,154
Change in fair value of product hedges	(1,041)	—	(986)	—
Change in fair value of cash flow hedges	—	2,075	—	5,018
Amortization of net loss on cash flow hedges	52	92	105	145
Amortization of prior service cost and net actuarial loss	—	614	—	998
Other comprehensive income	(989)	2,781	(881)	6,161
Comprehensive income	$ 56,381	$ 64,233	$104,802	$117,315

4. Asset Impairment

In second-quarter 2007, we recorded a $1.3 million charge against the earnings of our petroleum products pipeline system segment associated with an impairment of a certain section of our pipeline in Illinois and Missouri, most of which was idle. The impairment charge was included in operating expenses on our consolidated statements of income and the tables included in our segment disclosures noted below. An impairment analysis was initiated as a result of an offer from a third party to acquire these sections of pipe. The carrying value of the pipeline prior to the impairment was $3.0 million. The fair value of these assets was determined using discounted cash flow techniques.

5. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. Our segments are managed separately because each segment requires different marketing strategies and business knowledge. Management evaluates performance based on segment operating margin, which includes revenues from affiliates and external customers, operating expenses, product purchases and equity earnings. Transactions between our business segments are conducted and recorded on the same basis as transactions with third-party entities.

We believe that investors benefit from having access to the same financial measures being used 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 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 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 included in the tables below. Operating profit includes expense items, such as depreciation and amortization and G&A expenses, that management does not consider when evaluating the core profitability of our operations.

Beginning in 2007, commercial and operating responsibilities for our two inland terminals in the Dallas, Texas area were transferred from the petroleum products terminals segment to our petroleum products pipeline system segment. As a result, historical financial results for our segments have been adjusted to conform to the current period's presentation.

	Three Months Ended June 30, 2006 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 107,321	$ 28,771	$ 3,428	$ (965)	$ 138,555
Product sales revenues	169,975	2,831	—	—	172,806
Affiliate management fee revenue	172	—	—	—	172
Total revenues	277,468	31,602	3,428	(965)	311,533
Operating expenses	41,544	12,244	2,986	(1,729)	55,045
Product purchases	153,863	1,124	—	(130)	154,857
Equity earnings	(946)	—	—	—	(946)
Operating margin	83,007	18,234	442	894	102,577
Depreciation and amortization	9,775	4,497	190	894	15,356
Affiliate G&A expenses	11,155	4,024	558	—	15,737
Segment profit (loss)	$ 62,077	$ 9,713	$ (306)	$ —	$ 71,484

	Three Months Ended June 30, 2007 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 114,385	$ 32,014	$ 4,498	$ (827)	$ 150,070
Product sales revenues	174,471	3,431	—	—	177,902
Affiliate management fee revenue	183	—	—	—	183
Total revenues	289,039	35,445	4,498	(827)	328,155
Operating expenses	42,314	13,145	5,981	(1,413)	60,027
Product purchases	154,933	1,786	—	(131)	156,588
Equity earnings	(1,106)	—	—	—	(1,106)
Operating margin (loss)	92,898	20,514	(1,483)	717	112,646
Depreciation and amortization	9,795	4,989	194	717	15,695
Affiliate G&A expenses	12,703	4,412	626	—	17,741
Segment profit (loss)	$ 70,400	$ 11,113	$ (2,303)	$ —	$ 79,210

	Six Months Ended June 30, 2006 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 199,174	$ 63,142	$ 8,149	$ (1,719)	$ 268,746
Product sales revenues	315,439	6,263	—	—	321,702
Affiliate management fee revenue	345	—	—	—	345
Total revenues	514,958	69,405	8,149	(1,719)	590,793
Operating expenses	82,573	23,859	5,233	(3,235)	108,430
Product purchases	285,439	3,270	—	(257)	288,452
Equity earnings	(1,665)	—	—	—	(1,665)
Operating margin	148,611	42,276	2,916	1,773	195,576
Depreciation and amortization	19,500	8,904	380	1,773	30,557
Affiliate G&A expenses	21,974	7,699	1,091	—	30,764
Segment profit	$ 107,137	$ 25,673	$ 1,445	$ —	$ 134,255

	Six Months Ended June 30, 2007 (in thousands)				
	Petroleum Products Pipeline System	Petroleum Products Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$ 221,696	$ 63,763	$ 9,413	$ (1,651)	$ 293,221
Product sales revenues	318,736	7,829	—	—	326,565
Affiliate management fee revenue	356	—	—	—	356
Total revenues	540,788	71,592	9,413	(1,651)	620,142
Operating expenses	85,256	27,106	11,520	(2,880)	121,002
Product purchases	286,359	4,468	—	(259)	290,568
Equity earnings	(1,869)	—	—	—	(1,869)
Operating margin (loss)	171,042	40,018	(2,107)	1,488	210,441
Depreciation and amortization	19,425	9,832	390	1,488	31,135
Affiliate G&A expenses	25,233	8,939	1,254	—	35,426
Segment profit (loss)	$ 126,384	$ 21,247	$ (3,751)	$ —	$ 143,880

6. Related Party Disclosures

Affiliate Entity Transactions

We have a 50% ownership interest in Osage Pipe Line Company, LLC ("Osage Pipeline") and are paid a management fee for its operation. During both the three month periods ended June 30, 2006 and 2007, we received operating fees from Osage Pipeline of $0.2 million, which we reported as affiliate management fee revenue. Affiliate management fee revenue for the six months ended June 30, 2006 and 2007 was $0.3 million and $0.4 million, respectively.

Transactions between us and our affiliates are accounted for as affiliate transactions. The following table summarizes affiliate costs and expenses that are reflected in the accompanying consolidated statements of income (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	**2007**	**2006**	**2007**
MGG GP—allocated operating expenses	18,095	19,672	36,082	38,875
MGG GP—allocated G&A expenses	15,737	12,026	30,764	22,377

Under our services agreement with MGG GP, we reimburse MGG GP for costs of employees necessary to conduct our operations. The affiliate payroll and benefits accruals associated with this agreement at December 31, 2006 and June 30, 2007 were $18.7 million and $15.1 million, respectively, and the long-term affiliate pension and benefits accruals associated with this agreement at December 31, 2006 and June 30, 2007 were $29.3 million and $33.2 million, respectively. We settle our affiliate payroll, payroll-related expenses and non-pension postretirement benefit costs with MGG GP on a monthly basis. We settle our long-term affiliate pension liabilities through payments to MGG GP when MGG GP makes contributions to its pension funds.

MGG has 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. We do not expect to receive reimbursements under this agreement beyond 2008. The amount of G&A costs required to be reimbursed by MGG to us was $0.6 million and $1.0 million, respectively, for the three and six months ended June 30, 2006, and $0.3 million and $0.6 million, respectively, for the three and six months ended June 30, 2007. Reimbursable G&A costs for the three and six months ended June 30, 2007 also included a $1.3 million non-cash expense related to a payment by MGG Midstream Holdings, L.P. ("MGG MH"), an affiliate which owns MGG GP, to one of our executive officers in connection with the April sale by MGG MH of limited partner interests in MGG.

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"). During 2006 and through January 30, 2007, one or more of the members of our general partner's eight-member board of directors were representatives of CRF. The board of directors of our general partner adopted procedures internally to assure that our proprietary and confidential information was protected from disclosure to competing companies in which CRF owned an interest. As part of these procedures, CRF agreed that none of its representatives would serve on our general partners' board of directors and on the boards of directors of competing companies in which CRF owned an interest. CRF is part of an investment group that has purchased Kinder Morgan, Inc. To alleviate competitive concerns the Federal Trade Commission ("FTC") raised regarding this transaction, CRF agreed with the FTC to remove their representatives from our general partner's board of directors. CRF's agreement with the FTC was announced on January 25, 2007, and as of January 30, 2007, all of the representatives of CRF voluntarily resigned from the board of directors of our general partner.

CRF has total combined general and limited partner interests in SemGroup, L.P. ("SemGroup") of approximately 30%. One of the members of the seven-member board of directors of SemGroup's general partner is a representative of CRF, with three votes on that board. Through our affiliates, we are a party to a number of arms-length transactions with SemGroup and its affiliates, and we have historically disclosed these transactions as related party transactions. For accounting purposes, we have not classified SemGroup as a related party since the voluntary resignation of the CRF representatives from our general partner's board of directors as of January 30, 2007. A summary of our transactions with SemGroup during 2006 and for the period from January 1, 2007 through January 30, 2007 is provided in the following table (in millions):

	Three Months Ended June 30, 2006	Six Months Ended June 30, 2006	Period From January 1, 2007 Through January 30, 2007
Product sales revenues	$ 32.9	$ 61.1	$ 20.5
Product purchases	9.8	20.8	14.5
Terminalling and other services revenues	1.4	3.0	0.3
Storage tank lease revenues	0.9	1.7	0.4
Storage tank lease expense	0.3	0.5	0.1

In addition to the above, we provide common carrier transportation services to SemGroup. As of December 31, 2006, we had recognized a receivable of $4.0 million from and a payable of $18.8 million to SemGroup and its affiliates. The receivable was included with the accounts receivable amount and the payable was included with the accounts payable amount on our December 31, 2006 consolidated balance sheet.

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 under a 10-year operating lease. Through June 30, 2006, we had received $4.0 million associated with this transaction from SemGroup's affiliate, which we reported as prepaid construction costs from related party on our consolidated statement of cash flows. We received no funds associated with this transaction during the 2007 period in which SemGroup was classified as a related party.

John P. DesBarres serves as an independent board member of our general partner's board of directors and also serves as a board member for American Electric Power Company, Inc. ("AEP"). During the three and six months ended June 30, 2006, our operating expenses included $0.8 million and $1.5 million, respectively, of power costs incurred with Public Service Company of Oklahoma ("PSO"), which is a subsidiary of AEP. During the three and six months ended June 30, 2007, our operating expenses included $0.7 million and $1.3 million, respectively, of power costs incurred with PSO. We had a $0.2 million receivable from PSO at June 30, 2007 resulting from an annual stand-by agreement for fuel oil. We had no other amounts payable to or receivable from PSO or AEP at December 31, 2006 or June 30, 2007.

Because our distributions have exceeded target levels as specified in our partnership agreement, our general partner receives approximately 50% of any incremental cash distributed per limited partner unit. As of June 30, 2007, our executive officers collectively own approximately 5% of MGG MH, which currently owns approximately 28% of MGG, the owner of our general partner; therefore, our executive officers also benefit from distributions to our general partner. 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 $0.63 per unit, our general partner would receive annual distributions of approximately $72.1 million on its combined general partner interest and incentive distribution rights.

7. Inventory

Inventory at December 31, 2006 and June 30, 2007 was as follows (in thousands):

	December 31, 2006	June 30, 2007
Refined petroleum products	$ 45,839	$ 24,040
Natural gas liquids	28,848	31,001
Transmix	14,449	37,046
Additives	2,026	2,855
Other	388	378
Total inventory	$ 91,550	$ 95,320

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 in McPherson, Kansas ("NCRA"). The 135-mile Osage pipeline transports crude oil from Cushing, Oklahoma to El Dorado, Kansas and has connections to the NCRA refinery and the Frontier refinery in El Dorado, Kansas. Our agreement with NCRA calls for equal sharing of Osage Pipeline's net income. Income from our equity investment in Osage Pipeline is included with our petroleum products pipeline system. Summarized financial information for Osage Pipeline for the three and six months ended June 30, 2006 and 2007 is presented below (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2007	2006	2007
Revenues	$ 3,866	$ 3,903	$ 7,154	$ 7,423
Net income	$ 2,225	$ 2,544	$ 3,995	$ 4,402

Condensed balance sheets for Osage Pipeline as of December 31, 2006 and June 30, 2007 are presented below (in thousands):

	December 31, 2006	June 30, 2007
Current assets	$ 5,015	$ 4,696
Noncurrent assets	$ 4,278	$ 4,251
Current liabilities	$ 697	$ 599
Members' equity	$ 8,596	$ 8,348

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

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2007
Investment at beginning of period	$ 24,888	$ 24,087
Earnings in equity investment:		
Proportionate share of earnings	1,997	2,201
Amortization of excess investment	(332)	(332)
Net earnings in equity investment	1,665	1,869
Cash distributions	(2,025)	(2,325)
Equity investment at end of period	$ 24,528	$ 23,631

Our initial investment in Osage Pipeline included an excess net investment amount of $21.7 million, which is being amortized over the average lives of Osage Pipeline's assets. 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. The unamortized excess net investment amount at December 31, 2006 and June 30, 2007 was $19.8 million and $19.5 million, respectively, and represents additional value of the underlying identifiable assets.

9. Employee Benefit Plans

MGG GP sponsors a pension plan for union employees, a pension plan for non-union employees and a postretirement benefit plan for selected employees. The following table presents our consolidated net periodic benefit costs related to these plans during the three and six months ended June 30, 2006 and 2007 (in thousands):

	Three Months Ended June 30, 2006		Six Months Ended June 30, 2006	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of Net Periodic Benefit Costs:				
Service cost	$ 1,565	$ 140	$ 2,794	$ 280
Interest cost	562	270	1,103	540
Expected return on plan assets	(395)	—	(953)	—
Amortization of prior service cost	170	449	339	899
Amortization of actuarial loss	17	116	269	231
Net periodic benefit cost	$ 1,919	$ 975	$ 3,552	$ 1,950

	Three Months Ended June 30, 2007		Six Months Ended June 30, 2007	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of Net Periodic Benefit Costs:				
Service cost	$ 1,423	$ 143	$ 2,897	$ 267
Interest cost	656	288	1,290	513
Expected return on plan assets	(519)	—	(1,092)	—
Amortization of prior service cost	170	43	339	88
Amortization of actuarial loss	168	233	227	344
Net periodic benefit cost	$ 1,898	$ 707	$ 3,661	$ 1,212

10. Debt

Our debt at December 31, 2006 and June 30, 2007 was as follows (in thousands):

	December 31, 2006	June 30, 2007
Revolving credit facility	$ 20,500	$ 122,000
6.45% Notes due 2014	249,589	249,611
5.65% Notes due 2016	248,520	244,946
6.40% Notes due 2037	—	248,902
Magellan Pipeline notes	270,839	—
Total debt	$ 789,448	$ 865,459

Our debt and the debt of our consolidated subsidiaries is non-recourse to our general partner.

Revolving Credit Facility. Our revolving credit facility has a borrowing capacity of $400 million and matures in May 2011. Borrowings under the facility are unsecured and incur interest at LIBOR plus a spread that ranges from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. As of June 30, 2007, $122.0 million was outstanding under this facility, and $1.1 million was obligated for letters of credit. The obligations for letters of credit are not reflected as debt on our consolidated balance sheets. The weighted-average interest rate on borrowings outstanding under the facility at June 30, 2006 and 2007 was 5.7% and 5.8%, respectively.

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 of senior notes due 2016 in an underwritten public offering. 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 June 30, 2006 and 2007 was 6.1% 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 was decreased by $1.2 million and $4.8 million at December 31, 2006 and June 30, 2007, respectively, for the fair value of the associated hedge.

6.40% Notes due 2037. On April 19, 2007, we issued $250.0 million of 6.4% notes due 2037 in an underwritten public offering. The notes were issued for the discounted price of 99.6%, or $248.9 million, and the discount is being accreted over the life of the notes. Net proceeds from the offering, after underwriter discounts of $2.2 million and offering costs of $0.3 million, were $246.4 million. The net proceeds from this offering were used to repay our Magellan Pipeline notes, as discussed below. 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%.

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. At December 31, 2006, $272.6 million of senior notes were outstanding pursuant to this agreement, which were reflected as current portion of long-term debt on our consolidated balance sheets. The outstanding principal amount of the notes at December 31, 2006 was decreased by $1.8 million for the fair value of associated hedges (see Note 11–Derivative Financial Instruments). We repaid these notes on May 3, 2007, together with a make-whole premium of $2.0 million and accrued interest of $1.5 million, with net proceeds from a $250.0 million public offering of 30-year senior notes (see *6.40% Notes due 2037*) and borrowings under our revolving credit facility. Prior to this repayment, we made deposits in an escrow account in anticipation of semi-annual interest payments on these notes. Deposits of $5.3 million at December 31, 2006 were reflected as restricted cash on our consolidated balance sheet.

11. Derivative Financial Instruments

We use interest rate derivatives to help us manage interest rate risk. The following table summarizes cash flow hedges we had settled and recorded to other comprehensive income (loss) as of June 30, 2007 associated with various debt offerings (dollars in millions):

Hedge	Date	Gain/(Loss)	Amortization Period
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
Interest rate swaps	April 2007	5.3	30-year life of 6.40% notes

The following are hedges settled during the current period:

- In September and November 2006, we entered into forward starting interest rate swap agreements to hedge against the variability of future interest payments on $250.0 million of debt we issued in April 2007. These agreements were unwound and settled in April 2007, in conjunction with our public offering of $250.0 million of notes. We received $5.5 million from the settlement of these agreements, of which $5.3 million was recorded to other comprehensive income and is being amortized against interest expense over the life of the notes, and $0.2 million was considered ineffective and recorded as other income. This hedge settlement is included in the above table.

- During May 2004, we entered into certain interest rate swap agreements with notional amounts of $250.0 million to hedge against changes in the fair value of a portion of the Magellan Pipeline notes. The fair value of these hedges at December 31, 2006 was $(1.8) million, which was recorded to other current liabilities and current portion of long-term debt. We unwound these agreements on May 3, 2007 in conjunction with the repayment of the Magellan Pipeline notes, resulting in payments totaling $1.1 million to the hedge counterparties, of which $0.9 million was recorded to other expense and $0.2 million was recorded as a reduction of accrued interest.

Additionally, 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 agreement 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 the related notes. Payments settle in April and October each year with LIBOR set in arrears. During each period we record the impact of this swap based on the forward LIBOR curve. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR results 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, 2006 and June 30, 2007, respectively, was $(1.2) million and $(4.8) million, which was recorded to other deferred liabilities and long-term debt.

We also use derivatives to help us manage product purchases and sales. Derivatives that qualify for and are designated as normal purchases and sales are accounted for using traditional accrual accounting. As of June 30, 2007, we had commitments under forward purchase contracts for product purchases that will be accounted for as normal purchases totaling approximately $6.0 million. Additionally, we had commitments under forward sales contracts for product sales that will be accounted for as normal sales totaling approximately $51.3 million.

12. Commitments and Contingencies

Environmental Liabilities. Liabilities recognized for estimated environmental costs were $57.8 million and $61.0 million at December 31, 2006 and June 30, 2007, respectively. Environmental liabilities have been classified as current or noncurrent based on management’s estimates regarding the timing of actual payments. Management estimates that expenditures associated with these environmental remediation liabilities will be paid over the next ten years.

Our environmental liabilities include, among other items, accruals for the items discussed below:

Petroleum Products EPA Issue. In July 2001, the Environmental Protection Agency ("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. We have accrued an amount for this matter based on our best estimates that is less than $22.0 million. Most of the amount we have accrued for this matter was included as part of the environmental indemnification settlement we reached with our former affiliate (see *Indemnification Settlement* description below). 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. We are in ongoing negotiations with the EPA; however, we are unable to determine what our ultimate liability could be for this matter. Adjustments to our recorded liability resulting from a final settlement with the EPA 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 June 30, 2007, we have estimated remediation costs associated with this release of approximately $2.8 million. Through June 30, 2007, we have spent $2.0 million on remediation associated with this release and, as of June 30, 2007, have recorded associated environmental liabilities of $0.8 million. We have recognized a receivable of $1.2 million from our insurance carrier for this matter. We have included this release with the other releases discussed in *Petroleum Products 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 June 30, 2007, we have estimated remediation costs associated with this release of approximately $8.4 million. Through June 30, 2007, we have spent $3.3 million on remediation associated with this release and, as of June 30, 2007, have recorded associated environmental liabilities of $5.1 million and a receivable of $3.6 million from our insurance carrier. We have included this release with the other releases discussed in *Petroleum Products EPA Issue* above in negotiating any penalties or other injunctive relief that might be assessed.

Polychlorinated Biphenyls ("PCB") Impacts. We have identified PCB impacts at one of our petroleum products terminals that we are in the process of delineating. It is possible that in the near term, after our delineation process is complete, the PCB contamination levels could require corrective actions. We are unable at this time to determine what the corrective actions and associated costs might be; however, the costs of these corrective actions could be material to our results of operations and cash flows. These items would have been considered covered by the indemnity agreement settled in May 2004 (see *Indemnification Settlement* below), and as a result, any associated costs would be allocated to our general partner.

Ammonia EPA Issue. In February 2007, we received notice from the DOJ that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Sections 301 and 311 of the Act with respect to two releases of anhydrous ammonia from the ammonia pipeline owned by us and operated by a third party. The DOJ stated that the maximum statutory penalty for alleged violations of the Act for both releases combined was approximately $13.2 million. The DOJ also alleged that the third-party operator of our ammonia pipeline was liable for penalties pursuant to Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act for failure to report the releases on a timely basis, with the statutory maximum for those penalties as high as $4.2 million. In March 2007, we received a demand from the third-party operator for defense and indemnification in regards to a DOJ criminal investigation regarding whether certain actions or omissions of the third-party operator constituted violations of federal criminal statutes. We believe that we do not have an obligation to indemnify or defend the third-party operator against the DOJ criminal investigations. The DOJ stated in its notice to us that it does not expect us or the third-party operator to pay the penalties at the statutory maximum; however, it may seek injunctive relief if the parties cannot agree on any necessary corrective actions. We have accrued an amount for this matter based on our best estimates that is less than the maximum statutory penalties. We are currently in discussions with the EPA, DOJ and the third-party operator regarding these two releases; however, we are unable to determine what our ultimate liability could be for this matter. Adjustments to our recorded liability resulting from a final settlement with the EPA, which could occur in the near term, could be material to our results of operations and cash flows.

Indemnification Settlement. Prior to May 2004, a former affiliate had agreed to indemnify us against, among other things, certain environmental losses associated with assets contributed to us at the time of our initial public offering or which we subsequently acquired from this former affiliate. In May 2004, our general partner entered into an agreement under which our former affiliate agreed to pay us $117.5 million to release it from these indemnifications. On June 29, 2007, we received the final $35.0 million installment payment associated with this agreement, which we recorded as a capital contribution. While the settlement agreement releases our former affiliate from its environmental and certain other indemnifications, some 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.

At both December 31, 2006 and June 30, 2007, known liabilities that would have been covered by this indemnity agreement were $45.7 million. Through June 30, 2007, we have spent $36.8 million of the $117.5 million indemnification settlement amount for indemnified matters, including $15.4 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.

Environmental Receivables. Receivables from insurance carriers and other entities related to environmental matters were $5.9 million and $6.7 million at December 31, 2006 and June 30, 2007, respectively.

Unrecognized product gains. Our petroleum products terminals operations generate product overages and shortages. When our petroleum products terminals experience net product shortages, we recognize expense for those losses in the periods in which they occur. When our petroleum products terminals experience net product overages, we have product on hand for which we have no cost basis. Therefore, these net overages are not recognized in our financial statements until the associated barrels are either sold or used to offset product losses. The combined net unrecognized product overages for our petroleum products terminals operations had a market value of approximately $8.9 million as of June 30, 2007. 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 (“LTIP”) for certain MGG GP employees who perform services for us and for directors of our general partner. The LTIP primarily consists of phantom units and permits the grant of awards covering an aggregate of 3.2 million limited partner units. The compensation committee of our general partner’s board of directors (the “Compensation Committee”) administers the LTIP.

The long-term incentive awards discussed below 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 award 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 under certain circumstances following a change in control of our general partner.

In February 2004, the Compensation Committee approved approximately 159,000 unit award grants pursuant to the LTIP. These units vested on December 31, 2006, and, because we exceeded certain performance metrics, the actual number of units awarded with this grant totaled approximately 285,000. The value of these units on December 31, 2006 was $11.0 million. We settled these award grants in January 2007 by issuing 184,905 common limited partner units and distributing those units to the participants. The difference between the units issued to the participants and the total units accrued for represented the minimum tax withholdings associated with this award settlement. We paid associated tax withholdings and employer taxes of $3.9 million and $0.5 million, respectively, in January 2007, which we intend to finance with proceeds from our next equity offering.

In February 2005, the Compensation Committee approved approximately 160,600 unit award grants pursuant to the LTIP. 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 units that could ultimately be issued under this award ranges from zero up to a total of 298,600 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 vest on December 31, 2007. As of June 30, 2007, approximately 11,300 award grants have been forfeited. We do not anticipate additional forfeitures prior to the vesting date. We have estimated the number of units that will be awarded under this grant to be approximately 283,700, the fair value of which was $45.32 per unit or $12.9 million on June 30, 2007. Unrecognized estimated compensation expense associated with these award grants as of June 30, 2007 was $2.1 million, which will be recognized over the next 6 months. There was no impact on our cash flows associated with these award grants during the first six months of 2006 and 2007.

During 2006, the Compensation Committee approved approximately 178,500 unit award grants pursuant to the LTIP. There was no impact on our cash flows associated with these award grants during the first six months of 2006 and 2007. These award grants are being accounted for as follows:

- Approximately 139,700 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 258,400 as adjusted for expected forfeitures and retirements. We have accounted for these award grants using the equity method. The weighted-average fair value of the awards on the grant date was $24.67 per unit, which was based on our unit price on the grant date less the present value of the per-unit estimated cash distributions during the vesting period. As of June 30, 2007, approximately 8,700 award grants have been forfeited and we expect an additional 1,800 will be forfeited prior to the vesting date. We increased our estimate of the number of payout units under this grant to approximately 232,700 because we believe we will achieve above-target results compared to the established performance metrics. The value of these award grants was $5.7 million on June 30, 2007, and the unrecognized compensation cost on that date was $3.0 million, which will be recognized over the next 18 months.

- Approximately 34,900 are based on personal performance and payouts will be determined by 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 64,600 as adjusted for expected forfeitures and retirements. We have accounted for these award grants using the liability method; therefore, the compensation expense we recognize is based on the fair value of the unit awards and the percentage of the service period completed at each period end. As of June 30, 2007, approximately 2,200 award grants have been forfeited and we expect an additional 400 will be forfeited prior to the vesting date. We increased our estimate of the number of payout units under this grant to approximately 58,200 because we believe the Compensation Committee will approve above-target discretionary payouts as they have historically done when above-target financial results are achieved. The fair value of these award grants was $42.76 per unit or $2.5 million on June 30, 2007, and the unrecognized estimated compensation cost on that date was $1.3 million, which will be recognized over the next 18 months.

- An additional 3,900 award grants were approved with various vesting dates. As of June 30, 2007, approximately 2,600 of these award grants have been forfeited. We are using the equity method to account for most of the remaining award grants. The value of these award grants was approximately $0.1 million on June 30, 2007, and the unrecognized estimated compensation cost on that date was less than $0.1 million, which will be recognized over the next 6 months.

In 2007, the Compensation Committee approved approximately 158,200 unit award grants pursuant to the LTIP. There was no impact on our cash flows from the award grants during the first six months of 2007. These award grants have a three-year vesting period which will end on December 31, 2009; however, the grants are broken equally into three tranches. Under the first tranche, 80% of the payouts are based on performance metrics set for the 2007 fiscal year. Under the second and third tranches, 80% of the payouts will be based on performance metrics that will be established in the first quarter of each respective year. Under all three tranches, 20% of the payouts are based on personal performance and payouts will be determined by the Compensation Committee. The first tranche of this award is being accounted for as follows:

- Approximately 42,200 of the unit awards are based on attainment of 2007 performance metrics. The number of units that could ultimately vest under this component of the award ranges from zero to approximately 80,600 as adjusted for expected forfeitures and retirements of 4.5%. We have accounted for these award grants using the equity method. The weighted-average fair value of the awards on the grant date was $32.74 per unit, which was based on our closing unit price on the grant date, less the present value of the per-unit estimated cash distributions during the vesting period. Management currently estimates that we will achieve an above-target payout; therefore, our current compensation expense accruals assumed that 59,100 units will vest under this component of the award grant, the fair value of which on June 30, 2007 was $1.9 million. The unrecognized compensation cost on that date was $1.7 million, which will be recognized over the next 30 months.

- Approximately 10,500 of the unit awards are based on personal performance. The number of units that could ultimately vest under this component of the award ranges from zero to approximately 20,200 as adjusted for expected forfeitures and retirements of 4.5%. We have accounted for these award grants using the liability method; therefore, the compensation expense we recognize is based on the fair value of unit awards and the percentage of the service period completed at each period end. The fair value of these unit awards at June 30, 2007 was $40.18 per unit. Management currently estimates that we will achieve an above-target payout; therefore, our current compensation expense accruals assumed that 14,800 units will vest under this component of the award grant. The fair value of these unit awards on June 30, 2007 was $0.6 million of which $0.1 million has been recognized as compensation expense. The estimated unrecognized compensation expense will be recognized over the next 30 months.

An additional 2,600 award grants were approved during 2007 which have a vesting date of December 31, 2008. We are using the equity method to account for these award grants. The value of these award grants was approximately $0.2 million on June 30, 2007, and the unrecognized estimated compensation cost on that date was less than $0.1 million, which will be recognized over the next 18 months.

Our equity-based incentive compensation expense for the three and six months ended June 30, 2006 and 2007 is summarized as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2007	2006	2007
Awards prior to 2004	$ —	$ —	$ (93)	$ —
2004 awards	1,046	—	1,728	519
2005 awards	835	1,197	1,586	3,487
2006 awards	374	743	563	1,485
2007 awards	—	270	—	369
Total	$ 2,255	$ 2,210	$ 3,784	$ 5,860

14. Distributions

We paid the following distributions during 2006 and 2007 (in thousands, except per unit amounts):

Date Cash Distribution Paid	Per Unit Cash Distribution Amount	Common Units	Subordinated Units	General Partner	Total Cash Distribution
02/14/06	$ 0.55250	$ 33,526	$ 3,138	$ 12,839	$ 49,503
05/15/06	0.56500	37,494	—	13,668	51,162
08/14/06	0.57750	38,323	—	14,498	52,821
11/14/06	0.59000	39,153	—	15,327	54,480
Total	$ 2.28500	$ 148,496	$ 3,138	$ 56,332	$ 207,966
02/14/07	$ 0.60250	$ 40,094	$ —	$ 16,197	$ 56,291
05/15/07	0.61625	41,009	—	17,112	58,121
08/14/07(a)	0.63000	41,924	—	18,027	59,951
Total	$ 1.84875	$ 123,027	$ —	$ 51,336	$ 174,363

(a) Our general partner declared this cash distribution on July 27, 2007 to be paid on August 14, 2007 to unitholders of record at the close of business on August 6, 2007.

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 June 30, 2006			Six Months Ended June 30, 2006		
	Income (Numerator)	Units (Denominator)	Per Unit Amount	Income (Numerator)	Units (Denominator)	Per Unit Amount
Basic net income per limited partner unit	$ 41,143	66,361	$ 0.62	$ 77,828	66,361	$ 1.17
Effect of dilutive restricted unit grants	—	121	—	—	121	—
Diluted net income per limited partner unit	$ 41,143	66,482	$ 0.62	$ 77,828	66,482	$ 1.17

	Three Months Ended June 30, 2007			Six Months Ended June 30, 2007		
	Income (Numerator)	Units (Denominator)	Per Unit Amount	Income (Numerator)	Units (Denominator)	Per Unit Amount
Basic net income per limited partner unit	$ 43,790	66,549	$ 0.66	$ 80,641	66,543	$ 1.21
Effect of dilutive restricted unit grants	—	—	—	—	4	—
Diluted net income per limited partner unit	$ 43,790	66,549	$ 0.66	$ 80,641	66,547	$ 1.21

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

16. Fair Value Measurements

In September 2006, the Financial Accounting Standards Board adopted Statement of Financial Accounting Standards ("SFAS") No. 157, "Fair Value Measurements." SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years; however, earlier application was encouraged. We have elected to adopt SFAS No. 157 effective January 1, 2007. Our fair value measurements as of June 30, 2007 using significant other observable inputs for interest rate swap derivatives were $(4.8) million.

17. Subsequent Events

On July 27, 2007, our general partner declared a quarterly distribution of $0.63 per unit to be paid on August 14, 2007 to unitholders of record at the close of business on August 6, 2007. Total distributions to be paid under this declaration are approximately $60.0 million.

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 June 30, 2007, our three operating segments include:

- petroleum products pipeline system, which is primarily comprised of our 8,500-mile petroleum products pipeline system, including 47 terminals;
- petroleum products terminals, which principally includes our seven marine terminal facilities and 27 inland terminals; and
- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

Beginning in 2007, commercial and operating responsibilities for our two inland terminals in the Dallas, Texas area were transferred from the petroleum products terminals to the petroleum products pipeline system. As a result, our historical financial results and operating statistics have been adjusted to conform to the current period's presentation.

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 partnership. 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, 2006.

Recent Developments

Distribution. On July 27, 2007 the board of directors of our general partner declared a quarterly cash distribution of $0.63 per unit for the period of April 1 through June 30, 2007, representing the twenty-fifth consecutive distribution increase since our initial public offering in February 2001. The new quarterly distribution will be paid on August 14, 2007 to unitholders of record on August 6, 2007.

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 table below, is an important measure used by management to evaluate 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 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 included in the table 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 June 30, 2006 Compared to Three Months Ended June 30, 2007

	Three Months Ended June 30,		Variance Favorable (Unfavorable)	
	2006	2007	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Revenues:				
Transportation and terminals revenues:				
Petroleum products pipeline system	$ 107.3	$ 114.4	$ 7.1	7
Petroleum products terminals	28.8	32.0	3.2	11
Ammonia pipeline system	3.4	4.5	1.1	32
Intersegment eliminations	(0.9)	(0.8)	0.1	11
Total transportation and terminals revenues	138.6	150.1	11.5	8
Product sales	172.8	177.9	5.1	3
Affiliate management fees	0.2	0.2	—	—
Total revenues	311.6	328.2	16.6	5
Operating expenses:				
Petroleum products pipeline system	41.5	42.3	(0.8)	(2)
Petroleum products terminals	12.2	13.1	(0.9)	(7)
Ammonia pipeline system	3.0	6.0	(3.0)	(100)
Intersegment eliminations	(1.7)	(1.4)	(0.3)	(18)
Total operating expenses	55.0	60.0	(5.0)	(9)
Product purchases	154.9	156.6	(1.7)	(1)
Equity earnings	(0.9)	(1.1)	0.2	22
Operating margin	102.6	112.7	10.1	10
Depreciation and amortization expense	15.4	15.7	(0.3)	(2)
Affiliate G&A expense	15.7	17.8	(2.1)	(13)
Operating profit	$ 71.5	$ 79.2	$ 7.7	11
Operating Statistics				
Petroleum products pipeline system:				
Transportation revenue per barrel shipped	$ 1.077	$ 1.146		
Volume shipped (million barrels)	78.2	76.9		
Petroleum products terminals:				
Marine terminal average storage utilized per month (million barrels)	20.4	21.3		
Inland terminal throughput (million barrels)	27.2	29.3		
Ammonia pipeline system:				
Volume shipped (thousand tons)	162	186		

Transportation and terminals revenues increased by $11.5 million resulting from higher revenues for each of our business segments as described below:

- an increase in petroleum products pipeline system revenues of $7.1 million primarily attributable to increased transportation revenues resulting from higher average transportation rates due to our mid-year 2006 tariff increase. Transportation volumes declined slightly due to temporary refinery production reductions during the current year. We also earned more ancillary revenues related to higher fees for leased storage as well as additional demand for our terminal, additive and renewable fuels services during 2007;

- an increase in petroleum products terminals revenues of $3.2 million due to higher revenues at both our marine and inland terminals. Marine revenues increased primarily due to operating results from expansion projects, such as construction of additional storage tanks at our Galena Park, Texas facility that were placed into service beginning late 2006, as well as more revenue from additive services. Inland terminal revenues increased due to record throughput volumes during the current period as well as higher additive fees; and

- an increase in ammonia pipeline system revenues of $1.1 million primarily due to increased transportation volumes and higher average tariffs.

Operating expenses increased by $5.0 million resulting from higher expenses for each of our business segments as described below:

- an increase in petroleum products pipeline system expenses of $0.8 million primarily due to increased environmental accruals and power costs during the 2007 period, partially offset by more favorable product overages, which reduce operating expenses;

- an increase in petroleum products terminals expenses of $0.9 million primarily related to timing of maintenance projects, such as tank inspection and cleaning, at our marine terminals; and

- an increase in ammonia pipeline system expenses of $3.0 million primarily due to increased environmental accruals related to a 2004 pipeline release and higher system integrity costs. We expect the amount of 2007 system integrity spending on our ammonia system to be higher than in 2006 as we complete the work necessary for the high consequence area testing mandated by federal regulations.

Product sales revenues primarily resulted from a third-party product supply agreement, our petroleum products blending operation, terminal product gains and transmix fractionation. Revenues from product sales were $177.9 million for the three months ended June 30, 2007 while product purchases were $156.6 million, resulting in gross margin from these transactions of $21.3 million. The gross margin resulting from product sales and purchases for the 2007 period increased $3.4 million compared to gross margin for the 2006 period of $17.9 million, resulting from product sales for the three months ended June 30, 2006 of $172.8 million and product purchases of $154.9 million. The gross margin increase in the current period primarily resulted from the impact of high product prices. As we have previously disclosed, the gross margin we realize on our third-party supply agreement, petroleum products blending, terminal product gains and fractionation activities can be substantially higher in periods when refined petroleum 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 $10.1 million, primarily due to higher petroleum products pipeline system revenues, operating results from marine terminal expansion projects and higher gross margin from product sales, partially offset by increased ammonia operating expenses in 2007.

Affiliate G&A expenses increased by $2.1 million between periods. We recognized $1.3 million of non-cash expense during second quarter 2007 associated with a payment by MGG Midstream Holdings, L.P. ("MGG MH"), an affiliate indirectly owning a portion of our general partner, to one of our executive officers in connection with the April sale by MGG MH of limited partner interests in MGG. G&A costs also increased due to higher personnel costs as well as timing of expenses. Equity-based incentive compensation expense was unchanged at $1.9 million for both periods.

Interest expense, net of capitalized interest and interest income, was $13.1 million for the three months ended June 30, 2007, which was slightly lower than the $13.4 million related to the three months ended June 30, 2006. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $910.7 million during 2007 from $797.1 million during 2006 principally due to borrowings on our revolving credit facility to fund capital expenditures. However, the weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, decreased to 6.6% in the current period from 7.2% in 2006 primarily due to the refinancing of our pipeline notes during second quarter 2007 at a lower interest rate. Further, the amount of capitalized interest increased due to the higher level of capital spending over the last year.

We incurred debt refinancing expenses of $3.5 million during second quarter 2007 with no similar expense in the 2006 period. These expenses were associated with the early retirement of our pipeline notes, originally due in October 2007, and included a debt prepayment premium of $2.0 million, write-off of unamortized debt placement fee of $0.8 million and related interest rate hedge settlements of $0.7 million, which was recorded as other expense.

Provision for income taxes was $0.8 million in second quarter 2007 compared to $0.0 million in 2006. Beginning in 2007, the state of Texas implemented a partnership-level tax based on the financial results of our assets apportioned to the state of Texas.

Net income was $61.5 million for the three months ended June 30, 2007 compared to $57.4 million for the three months ended June 30, 2006, an increase of $4.1 million, or 7%.

Six Months Ended June 30, 2006 Compared to Six Months Ended June 30, 2007

	Six Months Ended June 30,		Variance Favorable (Unfavorable)	
	2006	2007	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Revenues:				
Transportation and terminals revenues:				
Petroleum products pipeline system	$ 199.2	$ 221.7	$ 22.5	11
Petroleum products terminals	63.1	63.8	0.7	1
Ammonia pipeline system	8.2	9.4	1.2	15
Intersegment eliminations	(1.7)	(1.7)	—	—
Total transportation and terminals revenues	268.8	293.2	24.4	9
Product sales	321.7	326.6	4.9	2
Affiliate management fees	0.3	0.3	—	—
Total revenues	590.8	620.1	29.3	5
Operating expenses:				
Petroleum products pipeline system	82.6	85.3	(2.7)	(3)
Petroleum products terminals	23.8	27.1	(3.3)	(14)
Ammonia pipeline system	5.2	11.5	(6.3)	(121)
Intersegment eliminations	(3.2)	(2.9)	(0.3)	(9)
Total operating expenses	108.4	121.0	(12.6)	(12)
Product purchases	288.5	290.6	(2.1)	(1)
Equity earnings	(1.7)	(1.9)	0.2	12
Operating margin	195.6	210.4	14.8	8
Depreciation and amortization expense	30.5	31.1	(0.6)	(2)
Affiliate G&A expense	30.8	35.4	(4.6)	(15)
Operating profit	$ 134.3	$ 143.9	$ 9.6	7
Operating Statistics				
Petroleum products pipeline system:				
Transportation revenue per barrel shipped	$ 1.053	$ 1.149		
Volume shipped (million barrels)	147.4	148.2		
Petroleum products terminals:				
Marine terminal average storage utilized per month (million barrels)	20.5	21.5		
Inland terminal throughput (million barrels)	52.4	57.5		
Ammonia pipeline system:				
Volume shipped (thousand tons)	378	400		

Transportation and terminals revenues increased by $24.4 million resulting from higher revenues for each of our business segments as described below:

- an increase in petroleum products pipeline system revenues of $22.5 million primarily attributable to increased transportation revenues resulting from higher average transportation rates due to our mid-year 2006 tariff increase. Transportation volumes increased slightly between periods due to higher diesel fuel shipments. We also earned more ancillary revenues related to higher fees for leased storage as well as additional demand for our terminal, additive and renewable fuels services during 2007;

- an increase in petroleum products terminals revenues of $0.7 million. Marine revenues were down slightly as operating results from expansion projects, such as construction of additional storage tanks at our Galena Park, Texas facility that were placed into service beginning late 2006, and more revenue from additive services and higher rates were offset by the first-quarter 2006 revenue recognition from a variable-rate storage agreement that ended January 2006. Although we currently have another variable-rate agreement in place, the term for the new contract expires in December 2007, at which time we will recognize any related revenues, which are based on our share of our customer's net trading profits earned over the agreement term. Inland terminal revenues increased in 2007 from higher throughput volumes as well as higher additive fees; and

- an increase in ammonia pipeline system revenues of $1.2 million primarily due to increased transportation volumes and higher average tariffs.

Operating expenses increased by $12.6 million. Each of our business segments incurred additional expenses as follows:

- an increase in petroleum products pipeline system expenses of $2.7 million primarily due to system integrity spending for pipeline testing and maintenance as well as higher personnel and environmental expenses. These increases were partially offset by more favorable product overages in the current period, which reduce operating expenses;
- an increase in petroleum products terminals expenses of $3.3 million primarily related to higher personnel costs, in part due to expansion projects, timing of maintenance projects and a product downgrade charge resulting from the accidental blending of a small amount of product during 2007; and
- an increase in ammonia pipeline system expenses of $6.3 million primarily due to increased environmental accruals related to a 2004 pipeline release and higher system integrity costs. We expect the amount of 2007 system integrity spending to be higher than in 2006 on our ammonia system as we complete the work necessary for the high consequence area testing mandated by federal regulations.

Product sales revenues primarily resulted from a third-party product supply agreement, our petroleum products blending operation, terminal product gains and transmix fractionation. Revenues from product sales were $326.6 million for the six months ended June 30, 2007, while product purchases were $290.6 million, resulting in gross margin from these transactions of $36.0 million. The gross margin resulting from product sales and purchases for the 2007 period increased $2.8 million compared to gross margin for the 2006 period of $33.2 million, resulting from product sales for the six months ended June 30, 2006 of $321.7 million and product purchases of $288.5 million. The gross margin increase in the current period primarily resulted from the impact of high product prices. As we have previously disclosed, the gross margin we realize on our third-party supply agreement, petroleum products blending, terminal product gains and fractionation activities can be substantially higher in periods when refined petroleum 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 $14.8 million, primarily due to higher petroleum products pipeline system revenues partially offset by increased ammonia operating expenses in 2007.

Depreciation and amortization expense increased by $0.6 million related to capital improvements over the past year.

Affiliate G&A expenses increased by $4.6 million between periods in part due to our equity-based incentive compensation program, which impacted G&A expenses by $5.1 million during the six months ended June 30, 2007 and $3.2 million during the comparable 2006 period. The higher compensation expense resulted from the increase in our unit price and increases in the number of units management estimates will vest under our equity-based incentive compensation program. G&A expenses were also higher due to a $1.3 million non-cash expense associated with a payment by MGG MH to one of our executive officers in connection with the April sale by MGG MH of limited partner interests in MGG during 2007 as well as higher personnel costs during the current year.

Interest expense, net of capitalized interest and interest income, was $26.7 million for the six months ended June 30, 2007, which was slightly lower than the $26.9 million related to the six months ended June 30, 2006. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $884.2 million during 2007 from $807.0 million during 2006 principally due to borrowings on our revolving credit facility to fund capital expenditures. However, the weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, decreased to 6.8% in the current period from 7.1% in 2006 primarily due to the refinancing of our pipeline notes during second quarter 2007 at a lower interest rate. Further, the amount of capitalized interest increased due to the higher level of capital spending over the last year.

We incurred debt refinancing expenses of $3.5 million during the 2007 period with no similar expense in 2006. These expenses were associated with the early retirement of our pipeline notes during second quarter 2007, originally due in October 2007, and included a debt prepayment premium of $2.0 million, write-off of unamortized debt placement fee of $0.8 million and related interest rate hedge settlements of $0.7 million, which was recorded as other expense.

Provision for income taxes was $1.5 million during the first half of 2007, compared to $0.0 million in 2006. Beginning in 2007, the state of Texas implemented a partnership-level tax based on the financial results of our assets apportioned to the state of Texas.

Net income was $111.2 million for the six months ended June 30, 2007 compared to $105.7 million for the six months ended June 30, 2006, an increase of $5.5 million, or 5%.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $104.7 million and $110.1 million for the six months ended June 30, 2007 and 2006, respectively.

- The $5.4 million decrease from 2006 to 2007 was primarily attributable to a $44.3 million decrease in cash relative to net changes in accounts payable and accrued product purchases. The decrease is primarily due to timing of invoices received from and payments to our vendors and suppliers.

- These decreases were partially offset by:

    > a $5.5 million increase in net income in 2007;

    > a $10.1 million increase in cash from collection of accounts receivable and other accounts receivable;

    > a $7.5 million increase in cash relative to net changes in environmental liabilities, offsetting non-cash expenses reflected in net income; and

    > all other working capital changes increased cash by $15.8 million.

Net cash used by investing activities for the six months ended June 30, 2007 and 2006 was $98.6 million and $62.6 million, respectively. During 2007, we spent $89.1 million for capital expenditures, of which $16.8 million was for maintenance capital and $72.3 million was for expansion capital. During 2006, we spent $67.1 million for capital expenditures, of which $12.2 million was for maintenance capital and $54.9 million was for expansion capital.

Net cash provided (used) by financing activities for the six months ended June 30, 2007 and 2006 was $0.8 million and ($83.6) million, respectively. Cash distributions paid to our unitholders and general partner were $114.4 million and $100.7 million for 2007 and 2006, respectively. Net borrowings on our revolving credit facility of $101.5 million and $248.9 million from a debt financing provided cash during 2007. These borrowings were used to repay the remaining $272.6 million on our pipeline notes. Capital contributions from our general partner were $37.3 million and $5.2 million during 2007 and 2006, respectively. Capital contributions for the current year include the final installment payment of $35.0 million from a former affiliate related to an indemnification settlement (see Environmental—*Indemnification Settlement* below).

During second quarter 2007, we paid $58.1 million in cash distributions to our unitholders and general partner. Based on the declared quarterly distribution of $0.63 per unit associated with the second quarter of 2007, we intend to pay $60.0 million in distributions during third quarter 2007. If we continue to pay cash distributions at this level, and the number of outstanding units remains the same, total cash distributions of $239.8 million would be paid on an annual basis. Of this amount, $72.1 million, or 30%, is related to our general partner's approximate 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 second quarter 2007, our net maintenance capital spending was $8.7 million, excluding $1.2 million of spending that would have been covered by indemnifications settled in May 2004 and $0.7 million for which we expect to be reimbursed by insurance. For the six months ended June 30, 2007, we have spent net maintenance capital of $13.9 million, excluding $2.1 million of spending that would have been covered by the May 2004 indemnification settlement and $0.8 million for which we expect to be reimbursed by insurance. We have received the entire $117.5 million under our indemnification settlement agreement. Please see Environmental below for additional description of this indemnification settlement.

For 2007, we expect to incur maintenance capital expenditures for our existing businesses of approximately $34.0 million, excluding $8.0 million of maintenance capital that would have been covered by the indemnification discussed above and $2.0 million we expect to receive from insurance reimbursements.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities. For the three and six months ended June 30, 2007, we spent cash of $39.2 million and $72.3 million, respectively, for organic growth projects. Based on projects currently underway, we currently plan to spend $160.0 million on organic growth capital in 2007, excluding future acquisitions, and approximately $90.0 million in 2008 to complete these projects.

Liquidity

As of June 30, 2007, total debt reported on our consolidated balance sheet was $865.5 million. The difference between this amount and the $872.0 million face value of our outstanding debt is adjustments related to fair value hedges and unamortized discounts on debt issuances.

Revolving Credit Facility. Our revolving credit facility has a borrowing capacity of $400.0 million and matures in May 2011. Borrowings under the facility are unsecured and incur interest at LIBOR plus a spread that ranges from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. As of June 30, 2007, $122.0 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 June 30, 2007, the weighted-average interest rate on borrowings outstanding under this facility was 5.8%.

6.45% Notes due 2014. On May 25, 2004, we sold $250.0 million of 6.45% notes due 2014 in an underwritten public offering at 99.8% of par. Including the impact of pre-issuance hedges associated with these notes, the effective interest rate on these notes at June 30, 2007 was 6.3%.

5.65% Notes due 2016. On October 15, 2004, we sold $250.0 million of 5.65% notes due 2016 in an underwritten public offering as part of the long-term financing of pipeline system assets we acquired in October 2004. The notes were issued at 99.9% of par. 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 June 30, 2007 was 6.0%.

6.40% Notes due 2037. On April 19, 2007, we sold $250.0 million of 6.40% notes due 2037 in an underwritten public offering at 99.6% of par. We received proceeds after underwriters' fees and expenses of approximately $246.4 million. Including the impact of pre-issuance hedges associated with these notes, the effective interest rate on these notes at June 30, 2007 was 6.3%. The proceeds from the offering of these notes together with borrowings under our revolving credit facility were used in May 2007 to prepay the $272.6 million of outstanding pipeline notes, as well as a related debt prepayment premium of $2.0 million and a $1.1 million payment in connection with the unwinding of fair value hedges associated with these notes.

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 derivative transaction as of June 30, 2007:

- 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% 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% notes.

Credit Ratings. Our current corporate credit ratings are BBB by Standard and Poor's and Baa2 by Moody's Investor Services.

Off-Balance Sheet Arrangements

None.

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 involves 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.

Indemnification settlement. Prior to May 2004, a former affiliate provided indemnifications to us for assets we had acquired from it. In May 2004, we entered into an agreement with our former affiliate under which our former affiliate agreed to pay us $117.5 million to release it from those indemnification obligations. As of June 30, 2007, we have received the entire $117.5 million due under this agreement. As of June 30, 2007, known liabilities that would have been covered by these indemnifications were $45.7 million. In addition, we have spent $36.8 million through June 30, 2007 that would have been covered by these indemnifications, including $15.4 million of capital costs. We have not reserved the cash received from this indemnity settlement but have used it for various other cash needs, including expansion capital spending.

Petroleum Products EPA issue. In July 2001, the Environmental Protection Agency (“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. We have accrued an amount for this matter based on our best estimates that is less than $22.0 million. Most of the amounts we have accrued for this matter were included as part of the environmental indemnification settlement we reached with our former affiliate, as described above. 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. We are in ongoing discussions with the EPA; however, we are unable to determine what our ultimate liability could be for this matter. Adjustments to our recorded liability resulting from a final settlement with the EPA could be material to our results of operations and cash flows.

Ammonia EPA issue. In February 2007, we received notice from the DOJ that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Sections 301 and 311 of the Act with respect to two releases of anhydrous ammonia from the ammonia pipeline owned by us and operated by a third party. The DOJ stated that the maximum statutory penalty for alleged violations of the Act for both releases combined was approximately $13.2 million. The DOJ also alleged that the third-party operator of our ammonia pipeline was liable for penalties pursuant to Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act for failure to report the releases on a timely basis, with the statutory maximum for those penalties as high as $4.2 million. In March 2007, we received a demand from the third-party operator for defense and indemnification in regards to a DOJ criminal investigation regarding whether certain actions or omissions of the third-party operator constituted violations of federal criminal statutes. We do not believe we have an obligation to indemnify or defend the third-party operator against the DOJ criminal investigations. The DOJ stated in its notice to us that it does not expect us or the third-party operator to pay the penalties at the statutory maximum; however, it may seek injunctive relief if the parties cannot agree on any necessary corrective actions. We have accrued an amount for this matter based on our best estimates that is less than the maximum statutory penalties. We are currently in discussions with the EPA, DOJ and third-party operator regarding these two releases; however, we are unable to determine what our ultimate liability could be for this matter. Adjustments to our recorded liability resulting from a final settlement with the EPA, which could occur in the near term, could be material to our results of operations and cash flows.

Polychlorinated Biphenyls ("PCB") impacts. We have identified PCB impacts at one of our petroleum products terminals that we are in the process of delineating. It is possible that in the near term after our delineation process is complete, the PCB contamination levels could require corrective actions. We are unable at this time to determine what these corrective actions and associated costs might be. These items would have been considered covered by the indemnity agreement settled in May 2004, as discussed above, and as a result would be allocated to our general partner. The costs of any corrective actions associated with these PCB impacts could be material to our results of operations and 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 current approved methodology is the producer price index for finished goods ("PPI-FG") plus 1.3%. Based on an actual change in PPI-FG of approximately 3.0%, the July 1, 2007 adjustment would result in a tariff increase of approximately 4.3% on that date. We increased virtually all of our published tariffs by the allowed adjustment of approximately 4.3% effective July 1, 2007.

Supply disruptions. Through direct refinery connections and interconnections with other interstate pipelines, our petroleum products pipeline system can access more than 40% of the refinery capacity in the continental United States. As a result, a single refinery disruption generally has minimal impact to our operations. During second quarter 2007, several refineries and a third-party pipeline system that supply our pipeline system were temporarily idled or curtailed production for various reasons, reducing the amount of product available for us to transport on our pipeline system. We expect similar supply disruptions to continue during third quarter 2007.

Ammonia operating agreement. A third-party pipeline company currently provides the operating services and a portion of the G&A services for our ammonia pipeline system under an operating agreement with us. This pipeline company has provided notice to us that it will not renew its operating agreement with us upon its scheduled expiration date of June 30, 2008. We do not expect the assumption of the operating responsibilities of our ammonia pipeline from this third-party operator to have a material impact on our operating expenses.

Unrecognized product gains. Our petroleum products terminals operations generate product overages and shortages. When our petroleum products terminals experience net product shortages, we recognize expense for those losses in the periods in which they occur. When our petroleum products terminals experience net product overages, we have product on hand for which we have no cost basis. Therefore, these net overages are not recognized in our financial statements until the associated barrels are either sold or used to offset product losses. The combined net unrecognized product overages for our petroleum products terminals operations had a market value of approximately $8.9 million as of June 30, 2007. 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.

Affiliate transactions. Since December 2005, MGG's general partner has provided the employees necessary to conduct our business operations and we reimburse it for these costs. In addition, MGG has agreed to reimburse us for G&A expenses, excluding equity-based compensation, in excess of a defined G&A cap. For the three and six months ended June 30, 2007, we were allocated operating expenses from MGG's general partner of $19.7 million and $38.9 million, respectively, and G&A expenses of $12.0 million and $22.4 million, respectively. For the three and six months ended June 30, 2006, we were allocated operating expenses from MGG's general partner of $18.1 million and $36.1 million, respectively, and G&A expenses of $15.7 million and $30.8 million, respectively. MGG reimbursed us for G&A costs of $0.3 million and $0.6 million for the three and six months ended June 30, 2007, respectively, and $0.6 million and $1.0 million for the three and six months ended June 30, 2006, respectively. Our G&A expenses for the three and six months ended June 30, 2007 also included a $1.3 million non-cash expense related to a payment by MGG MH to one of our executive officers in connection with the April 2007 sale by MGG MH of limited partner interests in MGG.

We own a 50% interest in a crude oil pipeline company. We earn a fee to operate this pipeline which was $0.2 million for both the three months ended June 30, 2007 and 2006 and $0.4 million and $0.3 million for the six months ended June 30, 2007 and 2006, respectively. We report these fees as affiliate management fee revenue on our consolidated statements of income.

Related party transactions. Because our distributions have exceeded target levels as specified in our partnership agreement, MGG indirectly receives approximately 50% of any incremental cash distributed per limited partner unit. The executive officers of our general partner collectively own approximately 5% of MGG Midstream Holdings, L.P., which currently owns 28% of MGG, and therefore 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 $0.63 per unit, MGG would receive annual distributions of approximately $72.1 million on its approximate 2% general partner interest and incentive distribution rights.

Impact of Inflation

Inflation is a factor in the United States economy and may increase the cost to acquire or replace property, plant and equipment and may increase the costs of labor and supplies. To the extent permitted by competition, regulation and our existing agreements, we have and will continue to pass through increased costs to our customers in the form of higher fees.

New Accounting Pronouncements

In February 2007, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 159, *"The Fair Value Option for Financial Assets and Financial Liabilities."* This Statement permits entities to choose to measure many financial instruments and certain other items at fair value, with the objective of mitigating volatility in reported earnings caused by measuring related assets and liabilities differently (without being required to apply complex hedge accounting provisions). We can make an election at the beginning of each fiscal year beginning after November 15, 2007 to adopt this standard. Currently, we do not expect to adopt this standard in 2008.

In January 2007, the FASB issued Revised Statement 133 Implementation Issue No. G19, *"Cash Flow Hedges: Hedging Interest Rate Risk for the Forecasted Issuances of Fixed-Rate Debt Arising from a Rollover Strategy."* This Implementation Issue clarified that in a cash flow hedge of a variable-rate financial asset or liability, the designated risk being hedged cannot be the risk of changes in its cash flows attributable to changes in the specifically identified benchmark rate if the cash flows of the hedged transaction are explicitly based on a different index. This Implementation Issue did not have a material impact on our results of operation, financial position or cash flows.

In January 2007, the FASB issued Statement 133 Implementation Issue No. G26, *"Cash Flow Hedges: Hedging Interest Cash Flows on Variable-Rate Assets and Liabilities That Are Not Based on a Benchmark Interest Rate."* This Implementation Issue clarified, given the guidance in Implementation Issue No. G19, that an entity may hedge the variability in cash flows by designating the hedged risk as the risk of overall changes in cash flows. This Implementation Issue did not have a material impact on our results of operation, financial position 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 June 30, 2007, we had $122.0 million outstanding on our variable rate revolving credit facility. We had no other variable rate debt outstanding; however, because of an interest rate swap agreement discussed below, we are exposed to variable interest rates on an additional $100.0 million of our debt. Considering this swap agreement and the amount outstanding on our revolving credit facility as of June 30, 2007, our annual interest expense would change by $0.3 million if LIBOR were to change by 0.125%.

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. We recognized a deferred liability of $4.8 million at June 30, 2007 for the fair value of this agreement.

We use derivatives to help us manage product purchases and sales. Derivatives that qualify for and are designated as normal purchases and sales are accounted for using traditional accrual accounting. As of June 30, 2007, we had commitments under forward purchase contracts for product purchases that will be accounted for as normal purchases totaling approximately $6.0 million. Additionally, we had commitments under forward sales contracts for product sales that will be accounted for as normal sales totaling approximately $51.3 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. Additionally, these disclosure controls and practices are effective in ensuring that information required to be disclosed is accumulated and communicated to our Chief Executive Officer and Chief Financial Officer to allow timely decisions regarding required disclosures.

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 not guarantees of future performance and are subject to numerous assumptions, uncertainties and risks that may cause future results to be materially different from the results stated or implied in such forward-looking statements included in this report.

The following are among the important factors that could cause future results to differ materially from any projected, forecasted, estimated or budgeted amounts that 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, crude 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 or state income tax purposes or if we become subject to significant forms of other taxation;

- 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 and 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 in control of our general partner, which 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 our 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 that 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.

This list of important factors is not exclusive. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events, changes in assumptions or otherwise.

PART II

OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In July 2001, the Environmental Protection Agency ("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. 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. We are in ongoing discussions with the EPA; however, we are unable to determine what our ultimate liability could be for this matter. Adjustments to our recorded liability resulting from a final settlement with the EPA 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.

In February 2007, we received notice from the DOJ that the EPA had requested the DOJ to initiate a lawsuit alleging violations of Sections 301 and 311 of the Act with respect to two releases of anhydrous ammonia from the ammonia pipeline owned by us and operated by a third party. The DOJ stated that the maximum statutory penalty for alleged violations of the Act for both releases combined was approximately $13.2 million. The DOJ also alleged that the third-party operator of our ammonia pipeline was liable for penalties pursuant to Section 103 of the Comprehensive Environmental Response, Compensation and Liability Act for failure to report the releases on a timely basis, with the statutory maximum for those penalties as high as $4.2 million. In March 2007, we received a demand from the third-party operator for defense and indemnification in regards to a DOJ criminal investigation regarding whether certain actions or omissions of the third-party operator constituted violations of federal criminal statutes. We believe that we do not have an obligation to indemnify or defend the third-party operator against the DOJ criminal investigations. The DOJ stated in its notice to us that it does not expect us or the third-party operator to pay the penalties at the statutory maximum; however, it may seek injunctive relief if the parties cannot agree on any necessary corrective actions. We have accrued an amount for this matter based on our best estimates that is less than the maximum statutory penalties. We are currently in discussions with the EPA, DOJ and the third-party operator regarding these two releases; however, we are unable to determine what our ultimate liability could be for this matter. Adjustments from amounts we currently have recorded to the final settlement amounts reached with the EPA could be material to our results of operations and cash flows.

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 information set forth below, 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, 2006, which could materially affect our business, financial condition or future results. The risks described below and 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 or operating results.

We have updated the following risk factors since issuing our Annual Report on Form 10-K:

Risks Related to Our Business

Rising short-term interest rates could increase our financing costs and reduce the amount of cash we generate.

Following a debt refinancing completed on May 3, 2007, we had fixed-rate debt of $750.0 million outstanding, excluding unaccreted discounts and fair value adjustments for interest rate hedges. We have effectively converted $100.0 million of this debt to floating-rate debt using an interest rate swap agreement. In addition, we had $122.0 million of floating rate borrowings outstanding on our revolving credit facility as of June 30, 2007. As a result of these swap agreements and revolver borrowings, we have exposure to changes in short-term interest rates. Rising short-term rates could reduce the amount of cash we generate and adversely affect our ability to pay cash distributions.

Restrictions contained in our debt instruments may limit our financial flexibility.

We are subject to restrictions with respect to our debt that may limit our flexibility in structuring or refinancing existing or future debt and prevent us from engaging in certain beneficial transactions. These restrictions include, among other provisions, the maintenance of certain financial ratios, as well as limitations on our ability to incur additional indebtedness, to grant liens, to sell assets or to repay existing debt without penalties. These restrictions could result in higher costs of borrowing and impair our ability to generate additional cash. In addition, a change in control of our general partner could, under certain circumstances, result in our debt becoming due and payable.

Risks Related to Our Partnership Structure

Potential conflicts of interest may arise among our general partner, its affiliates and us. Our general partner and its affiliates have limited fiduciary duties to us and our unitholders, which may permit them to favor their own interests to the detriment of us and our unitholders.

Conflicts of interest may arise among our general partner and it affiliates, including Magellan Midstream Holdings, L.P. (“MGG”), on the one hand, and us and our unitholders, on the other hand. The directors and officers of our general partner have fiduciary duties to manage us in a manner beneficial to us and our limited partners. At the same time, our general partner has a fiduciary duty to manage us in a manner beneficial to MGG, the owner of our general partner, and its affiliates. The board of directors of our general partner will resolve any such conflict and has broad latitude to consider the interests of all parties to the conflict. As a result of these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders.

These conflicts may include, among others, the following:

- our general partner is allowed to take into account the interests of parties other than us, including MGG, and their respective affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;

- our general partner determines whether or not we incur debt and that decision may affect our credit ratings;

- our general partner has limited its liability and reduced its fiduciary duties under the partnership agreement, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty;

- our general partner determines the amount and timing of our investment transactions, borrowings, issuances of additional partnership securities and reserves, each of which can affect the amount of cash that is available for distribution to our unitholders;

- our general partner, through its ownership of our incentive distribution rights, is entitled to receive increasing percentages, up to a maximum of 48%, of any incremental cash we distribute per limited partner unit, which could reduce our ability to complete accretive transactions or otherwise increase the amount of cash available for distribution to our unitholders;

- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;

- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered, or from entering into additional contractual arrangements with any of these entities on our behalf, so long as the terms of any such additional contractual arrangements are fair and reasonable to us;

- our general partner controls the enforcement of obligations owed to us by it and its affiliates;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us;
- our general partner determines the allocation of shared overhead expenses to MGG and us; and
- our general partner interprets and enforces contractual obligations between us and our affiliates, on the one hand, and MGG, on the other hand.

Certain executive officers of our general partner own interests in MGG Midstream Holdings, L.P. amounting to approximately 5% of its total ownership. MGG Midstream Holdings, L.P. currently owns the general partner interest and less than a majority of the limited partner interests in MGG. As a result, these officers could experience additional conflicts between our interests and the interests of MGG.

Affiliates of our general partner may compete with us.

Under our partnership agreement, it is not a breach of our general partner's fiduciary duties for affiliates of our general partner to engage in activities that compete with us. For example, both MGG, which owns our general partner, and MGG's general partner are partially owned by an affiliate of Carlyle/Riverstone Global Energy and Power Fund II, L.P. ("CRF"), which also owns, through affiliates, an interest in the general partner of SemGroup, L.P. ("SemGroup"), which is engaged in the transportation, storage and distribution of refined petroleum products and may acquire other entities that compete with us. We will compete directly with SemGroup and perhaps other entities in which CRF has an interest for acquisition opportunities throughout the United States and potentially will compete with SemGroup and these other entities for new business or extensions of the existing services provided by our operating partnerships, creating actual and potential conflicts of interest between us and affiliates of our general partner. In addition, an affiliate of SemGroup is a significant customer of ours.

The following are new risk factors since issuing our Annual Report on Form 10-K:

Tax Risks to Common Unitholders

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The Internal Revenue Service ("IRS") may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our current valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The tax treatment of our structure could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The U.S. federal income tax treatment of common unitholders depends in some instances on determinations of fact and interpretations of complex provisions of U.S. federal income tax law. You should be aware that the U.S. federal income tax rules are constantly under review by persons involved in the legislative process, the IRS and the U.S. Treasury Department, frequently resulting in revised interpretations of established concepts, statutory changes, revisions to Treasury Regulations and other modifications and interpretations. The IRS pays close attention to the proper application of tax laws to partnerships. The present U.S. federal income tax treatment of an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation (referred to as the "Qualifying Income Exception"), affect or cause us to change our business activities, affect the tax considerations of an investment in us, change the character or treatment of portions of our income and adversely affect an investment in our common units. For example, in response to certain recent developments, members of Congress are considering substantive changes to the definition of qualifying income under Internal Revenue Code section 7704(d) for the first time in 20 years. It is possible that these efforts could result in changes to the existing U.S. tax laws that affect publicly traded partnerships, including us. We are unable to predict whether any of these changes, or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units and the amount of cash available to pay as distributions to our unitholders.

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

The annual meeting of our limited partners was held on April 25, 2007. At this meeting, three individuals were elected as Class II directors of our general partner's board of directors. A tabulation of the voting on this issue follows:

Name	For	Withheld	Abstain	Broker Non-Votes
John P. DesBarres	61,971,663	456,429	—	—
Patrick C. Eilers	61,130,103	1,297,982	—	—
Thomas T. Macejko, Jr.	61,114,863	1,313,229	—	—

Also at this meeting, a proposal to amend the Magellan Midstream Partners' Long-Term Incentive Plan to increase the number of common units available under such plan was approved as follows:

For	Against	Abstain
30,887,597	2,390,497	487,103

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

*Exhibit 4.1 – Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed April 20, 2007).

*Exhibit 4.2 – First Supplemental Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed April 20, 2007).

*Exhibit 10.1 – Underwriting Agreement dated April 12, 2007 among Magellan Midstream Partners, L.P., Magellan GP, LLC, Magellan OLP, L.P., Magellan Operating GP, LLC, Magellan Pipeline Company, L.P., Magellan Pipeline Terminals, L.P., Magellan Pipeline GP, LLC, Wachovia Capital Markets, LLC and Citigroup Global Markets, Inc. (filed as Exhibit 10.1 to Form 8-K filed April 13, 2007).

*Exhibit 10.2 – Amendment to Magellan Midstream Partners' Long-Term Incentive Plan dated April 25, 2007 (filed as Exhibit 10.1 to Form 8-K filed April 26, 2007).

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 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 99.1 – Magellan GP, LLC balance sheets as of December 31, 2006 and June 30, 2007 and notes thereto.

* Each such exhibit has previously been 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 August 6, 2007.

MAGELLAN MIDSTREAM PARTNERS, L.P.

By: /s/ 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
*4.1	Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed April 20, 2007).
*4.2	First Supplemental Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed April 20, 2007).
*10.1	Underwriting Agreement dated April 12, 2007 among Magellan Midstream Partners, L.P., Magellan GP, LLC, Magellan OLP, L.P., Magellan Operating GP, LLC, Magellan Pipeline Company, L.P., Magellan Pipeline Terminals, L.P., Magellan Pipeline GP, LLC, Wachovia Capital Markets, LLC and Citigroup Global Markets, Inc. (filed as Exhibit 10.1 to Form 8-K filed April 13, 2007).
*10.2	Amendment to Magellan Midstream Partners' Long-Term Incentive Plan dated April 25, 2007 (filed as Exhibit 10.1 to Form 8-K filed April 26, 2007).
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 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.
99.1	Magellan GP, LLC balance sheets as of December 31, 2006 and June 30, 2007 and notes thereto.

* Each such exhibit has previously been 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)

	Twelve Months Ended December 31,					Six Months Ended June 30, 2007
	2002	2003	2004	2005	2006	
EARNINGS:						
Income from continuing operations before income taxes, extraordinary gain (loss) and cumulative effect of change in accounting principle*	$ 107,495	$ 88,169	$ 108,601	$ 156,379	$ 189,404	$ 110,809
Fixed charges	33,344	39,779	41,657	56,656	60,599	31,978
Amortization of capitalized interest	471	462	463	465	475	262
Distributed income of equity investees	—	—	—	3,300	4,125	2,325
Capitalized interest	(231)	(102)	(426)	(817)	(2,371)	(2,102)
Total earnings	$ 141,079	$ 128,308	$ 150,295	$ 215,983	$ 252,232	$ 143,272
FIXED CHARGES:						
Interest expense	$ 22,907	$ 36,597	$ 37,893	$ 52,554	$ 55,107	$ 27,837
Capitalized interest	231	102	426	817	2,371	2,102
Debt expense amortization	9,950	2,830	3,056	2,871	2,681	1,799
Rent expense representative of interest factor	256	250	282	414	440	240
Total fixed charges	$ 33,344	$ 39,779	$ 41,657	$ 56,656	$ 60,599	$ 31,978
Ratio of earnings to fixed charges	4.2	3.2	3.6	3.8	4.2	4.5

* Excludes income from equity investments and minority interest expense.