MAGELLAN MIDSTREAM PARTNERS LP
Form 10-Q
August 04, 2011
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2011

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 x No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No £

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company.

Large accelerated filer x Accelerated filer £ Non-accelerated filer £ Smaller reporting company £

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

As of August 3, 2011 there were 112,736,571 outstanding limited partner units of Magellan Midstream Partners, L.P. that trade on the New York Stock Exchange under the ticker symbol "MMP."

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PART I
FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED 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,	
	2010	2011	2010	2011
Transportation and terminals revenues	$193,173	$223,192	$366,342	$428,600
Product sales revenues	229,698	159,943	386,034	397,239
Affiliate management fee revenue	189	192	379	385
Total revenues	423,060	383,327	752,755	826,224
Costs and expenses:				
Operating	70,287	81,323	132,396	143,684
Product purchases	183,639	118,836	316,523	330,066
Depreciation and amortization	25,715	30,664	52,057	60,027
General and administrative	20,178	25,281	43,420	49,871
Total costs and expenses	299,819	256,104	544,396	583,648
Equity earnings	1,480	1,443	2,669	2,810
Operating profit	124,721	128,666	211,028	245,386
Interest expense	22,521	25,988	44,295	52,474
Interest income	(7)	(1)	(11)	(11)
Interest capitalized	(803)	(1,190)	(1,651)	(1,861)
Debt placement fee amortization expense	329	385	657	770
Income before provision for income taxes	102,681	103,484	167,738	194,014
Provision for income taxes	229	485	752	950
Net income	$102,452	$102,999	$166,986	$193,064
Allocation of net income (loss):				
Non-controlling owners’ interest	$(68)	$—	$(68)	$(63)
Limited partners’ interest	102,520	102,999	167,054	193,127
Net income	$102,452	$102,999	$166,986	$193,064
Basic and diluted net income per limited partner unit	$0.96	$0.91	$1.56	$1.71
Weighted average number of limited partner units outstanding used for basic and diluted net income per unit calculation	106,896	112,847	106,869	112,804

See notes to consolidated financial statements.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited, in thousands)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2011	2010	2011
Net income	$102,452	$102,999	166,986	193,064
Other comprehensive income:				
Net gain (loss) on commodity hedges	—	4,613	(289)	4,613
Reclassification of net gain on interest rate cash flow hedges to interest expense	(41)	(41)	(82)	(82)
Reclassification of net loss on commodity hedges to product sales revenues	—	—	2,035	—
Amortization of prior service credit and actuarial loss	(36)	77	(21)	155
Total other comprehensive income (loss)	(77)	4,649	1,643	4,686
Comprehensive income	102,375	107,648	168,629	197,750
Comprehensive loss attributable to non-controlling owners' interest in consolidated subsidiaries	(68)	—	(68)	(63)
Comprehensive income attributable to partners' capital	$102,443	$107,648	$168,697	$197,813

See notes to consolidated financial statements.

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

	December 31, 2010	June 30, 2011 (Unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$7,483	$12,992
Restricted cash	14,379	—
Trade accounts receivable (less allowance for doubtful accounts of $106 and $66 at December 31, 2010 and June 30, 2011, respectively)	92,192	70,074
Other accounts receivable	6,175	18,463
Inventory	216,408	285,996
Energy commodity derivatives deposits	22,302	43,505
Reimbursable costs	13,870	7,945
Other current assets	11,774	19,592
Total current assets	384,583	458,567
Property, plant and equipment	3,894,610	3,996,609
Less: accumulated depreciation	716,054	771,347
Net property, plant and equipment	3,178,556	3,225,262
Equity investments	23,728	27,395
Long-term receivables	1,167	1,710
Goodwill	39,925	39,961
Other intangibles (less accumulated amortization of $11,964 and $13,481 at December 31, 2010 and June 30, 2011, respectively)	16,924	16,506
Debt placement costs (less accumulated amortization of $5,439 and $6,209 at December 31, 2010 and June 30, 2011, respectively)	11,871	11,101
Tank bottom inventory	57,937	63,978
Other noncurrent assets	3,209	4,680
Total assets	$3,717,900	$3,849,160
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$41,425	$48,958
Accrued payroll and benefits	32,393	25,173
Accrued interest payable	35,799	36,171
Accrued taxes other than income	26,953	23,541
Environmental liabilities	12,202	17,410
Deferred revenue	34,733	30,442
Accrued product purchases	47,324	46,261
Energy commodity derivatives contracts	11,790	8,180
Contingent liabilities	1,730	15,755
Other current liabilities	30,698	21,123
Total current liabilities	275,047	273,014
Long-term debt	1,906,148	2,042,246
Long-term pension and benefits	28,965	31,704
Other noncurrent liabilities	17,597	22,516

Environmental liabilities	20,572	22,230
Commitments and contingencies		
Owners’ equity:		
Partners’ capital:		
Limited partner unitholders (112,481 units and 112,737 units outstanding at December 31, 2010 and June 30, 2011, respectively)	1,466,404	1,463,860
Accumulated other comprehensive loss	(11,096)	(6,410)
Total partners’ capital	1,455,308	1,457,450
Non-controlling owners’ interest in consolidated subsidiaries	14,263	—
Total owners’ equity	1,469,571	1,457,450
Total liabilities and owners’ equity	$3,717,900	$3,849,160

See notes to consolidated financial statements.

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

	Six Months Ended June 30,	
	2010	2011
Operating Activities:		
Net income	$166,986	$193,064
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	52,057	60,027
Debt placement fee amortization	657	770
Loss (gain) on sale, retirement and impairment of assets	(1,281)	7,106
Equity earnings	(2,669)	(2,810)
Distributions from equity investments	1,870	2,710
Equity-based incentive compensation expense	6,909	9,017
Amortization of prior service credit and actuarial loss	(21)	155
Changes in operating assets and liabilities:		
Restricted cash	—	14,379
Trade accounts receivable and other accounts receivable	9,320	9,830
Inventory	(15,799)	(69,588)
Energy commodity derivatives contracts, net of derivatives deposits	(2,525)	(14,159)
Reimbursable costs	2,585	5,925
Accounts payable	5,381	7,001
Accrued payroll and benefits	(7,898)	(7,220)
Accrued interest payable	(2,016)	372
Accrued taxes other than income	(1,348)	(3,412)
Accrued product purchases	2,799	(1,063)
Contingent liabilities	184	14,025
Tank bottom inventory	—	(6,041)
Current and noncurrent environmental liabilities	(3,898)	6,866
Other current and noncurrent assets and liabilities	2,009	(8,899)
Net cash provided by operating activities	213,302	218,055
Investing Activities:		
Property, plant and equipment:		
Additions to property, plant and equipment	(97,883)	(95,273)
Proceeds from sale and disposition of assets	5,128	753
Increase in accounts payable related to capital expenditures	3,888	532
Acquisition of assets	(29,300)	(17,798)
Acquisition of non-controlling owners' interests	—	(40,500)
Other	—	(4,600)
Net cash used by investing activities	(118,167)	(156,886)
Financing Activities:		
Distributions paid	(152,626)	(172,205)
Net borrowings under revolver	83,400	135,000
Net receipt from financial derivatives	9,565	—
Decrease in outstanding checks	(1,672)	(11,045)
Settlement of tax withholdings on long-term incentive compensation	(3,371)	(7,410)

Capital contributed by non-controlling owners	851	—
Other	(356)	—
Net cash used by financing activities	(64,209)	(55,660)
Change in cash and cash equivalents	30,926	5,509
Cash and cash equivalents at beginning of period	4,168	7,483
Cash and cash equivalents at end of period	$35,094	$12,992
Supplemental non-cash financing activity:		
Issuance of limited partner units in settlement of equity-based incentive plan awards	$2,034	$4,315
Non-cash capital contributed by non-controlling owners	$10,299	$—

See notes to consolidated financial statements.

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

1. Organization and Basis of Presentation
Organization
Unless indicated otherwise, the terms “our,” “we,” “us” and similar language refer to Magellan Midstream Partners, L.P. together with its subsidiaries. We are a Delaware limited partnership and our limited partner units are traded on the New York Stock Exchange under the ticker symbol “MMP.” Magellan GP, LLC (“MMP GP”), a wholly-owned Delaware limited liability company, serves as our general partner.
We operate and report in three business segments: the petroleum pipeline system, the petroleum 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.
Basis of Presentation
In the opinion of management, our accompanying consolidated financial statements, which are unaudited except for the consolidated balance sheet as of December 31, 2010, which is derived from our audited financial statements, include all normal and recurring adjustments necessary to present fairly our financial position as of June 30, 2011, and the results of operations for the three and six months ended June 30, 2010 and 2011 and cash flows for the six months ended June 30, 2010 and 2011. The results of operations for the six months ended June 30, 2011 are not necessarily indicative of the results to be expected for the full year ending December 31, 2011.
Pursuant to the rules and regulations of the Securities and Exchange Commission, the financial statements in this report 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, 2010.

2. Owners’ Equity

The changes in owners’ equity for the six months ended June 30, 2011 are provided in the table below (dollars in thousands):

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

	Limited Partners' Capital	Limited Partners' Accumulated Other Comprehensive Loss	Non-controlling Owners' Interest	Total Owners' Equity
Balance, January 1, 2011	$1,466,404	$ (11,096)	$14,263	$1,469,571
Comprehensive income:				
Net income (loss)	193,127	—	(63)	193,064
Net gain on commodity hedges	—	4,613	—	4,613
Reclassification of net gain on interest rate cash flow hedges to interest expense	—	(82)	—	(82)
Amortization of prior service credit and actuarial loss	—	155	—	155
Total other comprehensive income (loss)	193,127	4,686	(63)	197,750
Distributions	(172,205)	—	—	(172,205)
Equity method portion of equity-based incentive compensation expense	6,004	—	—	6,004
Issuance of 255,222 common units in settlement of long-term incentive plan awards and board of director retainer fees	4,315	—	—	4,315
Settlement of tax withholdings on long-term incentive compensation	(7,410)	—	—	(7,410)
Acquisition of non-controlling owners' interest	(26,300)	—	(14,200)	(40,500)
Other	(75)	—	—	(75)
Balance, June 30, 2011	$1,463,860	$ (6,410)	$—	$1,457,450

3. Acquisitions

Acquisitions of Assets

In January 2011, we acquired the remaining undivided interest in our Southlake, Texas terminal. We accounted for this purchase as an acquisition of assets. The operating results of the Southlake terminal are reported in our petroleum pipeline system segment.

In April 2011, we acquired an approximate 38-mile petroleum products pipeline segment connected to our petroleum pipeline system at Reagan, Texas. We accounted for this purchase as an acquisition of assets. The operating results of these assets have been included in our petroleum pipeline system segment from the acquisition date.

In May 2011, we acquired petroleum products storage tanks in Riverside, Missouri. We accounted for this purchase as an acquisition of assets. The operating results of these assets have been included in our petroleum pipeline system segment from the acquisition date.

Collectively, the costs for the above-noted asset acquisitions were $17.8 million.

Acquisition of Non-Controlling Owners' Interest

In February 2011, we acquired a private investment group's common equity in Magellan Crude Oil, LLC ("MCO") for $40.5 million, which represented all of the non-controlling owners' interest in subsidiaries on our consolidated balance sheet (see Note 2 - Owners' Equity). The operating results of MCO continue to be reported in our petroleum terminals segment.

Business Combination

In September 2010, we acquired certain assets from BP Pipelines (North America), Inc. ("BP") and accounted for this purchase as a business combination. We have not adjusted the preliminary purchase price and fair value of the assets acquired and liabilities assumed as reported in our Annual Report on Form 10-K for the year ended December 31, 2010 as we are still in the process of determining the fair value of the assets acquired and liabilities assumed. The final allocation of the purchase price will be made when that process is complete.

The following summarized pro forma consolidated income statement information assumes that the business acquired from BP referred to above occurred as of January 1, 2010. These pro forma results are for comparative purposes only and may not be indicative of the results that would have occurred had this acquisition been completed on January 1, 2010 or the results that will be attained in the future. The amounts presented below are in thousands:

	Three Months Ended June 30,			
	2010			2011
	As Reported	Pro Forma Adjustments	Pro Forma	As Reported
Revenues	$423,060	$13,820	$436,880	$383,327
Net income	$102,452	$4,645	$107,097	$102,999

	Six Months Ended June 30,			
	2010			2011
	As Reported	Pro Forma Adjustments	Pro Forma	As Reported
Revenues	$752,755	$27,456	$780,211	$826,224
Net income	$166,986	$10,950	$177,936	$193,064

Significant pro forma adjustments include historical results of the acquired assets and our calculation of general and administrative ("G&A") costs, depreciation expense and interest expense on borrowings necessary to finance the acquisition.

4. Product Sales Revenues

The amounts reported as product sales revenues on our consolidated statements of income include revenues from the physical sale of petroleum products and from mark-to-market adjustments from New York Mercantile Exchange (“NYMEX”) contracts. We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell from our business activities where we acquire or produce petroleum products. Some of these NYMEX contracts qualify for hedge accounting treatment and we designate and account for these as either cash flow or fair value hedges. The effective portion of the fair value changes in these contracts are recognized as adjustments to product sales when the hedged product is physically sold. Any ineffectiveness in these contracts is recognized as an adjustment to product sales in the period the ineffectiveness occurs. We account for those NYMEX contracts that do not qualify for hedge accounting treatment as economic hedges, with the period changes in fair value recognized as product sales. See Note 9 - Derivative Financial Instruments for further disclosures regarding our NYMEX contracts. For the three and six months ended June 30, 2010 and 2011, product sales revenues included the following (in thousands):

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2011	2010	2011
Physical sale of petroleum products	$205,932	$157,793	$371,237	$433,422
NYMEX contract adjustments:				
Change in value of NYMEX contracts that did not qualify for hedge accounting treatment and the effective portion of gains and losses of matured NYMEX contracts that qualified for hedge accounting treatment associated with our petroleum products blending and fractionation activities(1)	10,195	(1,078)	5,878	(21,058)
Change in value of NYMEX contracts that did not qualify for hedge accounting treatment associated with the Houston-to-El Paso pipeline section linefill working inventory(1)	13,571	3,228	8,919	(15,199)
Change in value of NYMEX contracts that did not qualify for hedge accounting treatment associated with our crude oil activities	—	—	—	74
Total NYMEX contract adjustments	23,766	2,150	14,797	(36,183)
Total product sales revenues	$229,698	$159,943	$386,034	$397,239

(1) The associated petroleum products for these activities are, to the extent still owned as of the statement date, or were, to the extent no longer owned as of the statement date, classified as inventories in current assets on our consolidated balance sheets.

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 used by management. Operating margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. Operating margin is not a generally accepted accounting principles (“GAAP”) measure but the components of operating margin are computed 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. Operating profit includes expense items, such as depreciation and amortization expense and G&A expenses, that management does not consider when evaluating the core profitability of our operations.

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

	Three Months Ended June 30, 2010 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$141,461	$48,446	$3,783	$(517)	$193,173
Product sales revenues	222,963	6,763	—	(28)	229,698
Affiliate management fee revenue	189	—	—	—	189
Total revenues	364,613	55,209	3,783	(545)	423,060
Operating expenses	49,450	18,262	3,235	(660)	70,287
Product purchases	182,267	1,917	—	(545)	183,639
Equity earnings	(1,480)	—	—	—	(1,480)
Operating margin	134,376	35,030	548	660	170,614
Depreciation and amortization expense	16,499	8,188	368	660	25,715
G&A expenses	14,490	5,104	584	—	20,178
Operating profit (loss)	$103,387	$21,738	$(404)	$—	$124,721

	Three Months Ended June 30, 2011 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$161,168	$56,969	$5,755	$(700)	$223,192
Product sales revenues	152,891	7,140	—	(88)	159,943
Affiliate management fee revenue	192	—	—	—	192
Total revenues	314,251	64,109	5,755	(788)	383,327
Operating expenses	51,737	26,627	3,726	(767)	81,323
Product purchases	117,540	2,084	—	(788)	118,836
Equity earnings	(1,443)	—	—	—	(1,443)
Operating margin	146,417	35,398	2,029	767	184,611
Depreciation and amortization expense	19,291	10,243	363	767	30,664
G&A expenses	18,783	5,838	660	—	25,281
Operating profit	$108,343	$19,317	$1,006	$—	$128,666

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

	Six Months Ended June 30, 2010 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$264,376	$94,105	$8,876	$(1,015)	$366,342
Product sales revenues	375,189	10,873	—	(28)	386,034
Affiliate management fee revenue	379	—	—	—	379
Total revenues	639,944	104,978	8,876	(1,043)	752,755
Operating expenses	92,270	34,635	7,216	(1,725)	132,396
Product purchases	313,043	4,523	—	(1,043)	316,523
Equity earnings	(2,669)	—	—	—	(2,669)
Operating margin	237,300	65,820	1,660	1,725	306,505
Depreciation and amortization expense	33,360	16,247	725	1,725	52,057
G&A expenses	31,342	10,878	1,200	—	43,420
Operating profit (loss)	$172,598	$38,695	$(265)	$—	$211,028

	Six Months Ended June 30, 2011 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$305,230	$112,190	$12,787	$(1,607)	$428,600
Product sales revenues	379,879	17,558	—	(198)	397,239
Affiliate management fee revenue	385	—	—	—	385
Total revenues	685,494	129,748	12,787	(1,805)	826,224
Operating expenses	89,447	48,623	7,057	(1,443)	143,684
Product purchases	326,013	5,858	—	(1,805)	330,066
Equity earnings	(2,810)	—	—	—	(2,810)
Operating margin	272,844	75,267	5,730	1,443	355,284
Depreciation and amortization expense	37,843	20,014	727	1,443	60,027
G&A expenses	37,238	11,309	1,324	—	49,871
Operating profit	$197,763	$43,944	$3,679	$—	$245,386

6. Inventory
Inventory at December 31, 2010 and June 30, 2011 was as follows (in thousands):

	December 31, 2010	June 30, 2011
Refined petroleum products	$146,211	$142,398
Natural gas liquids	27,982	72,195
Transmix	32,277	49,023
Crude oil	5,008	15,822
Additives	4,930	6,558
Total inventory	$216,408	$285,996

The increase in natural gas liquids was due to the purchase of butane during 2011 in anticipation of the petroleum products blending season, which begins each September.

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

7. Employee Benefit Plans

We sponsor two union pension plans for certain employees and a pension plan primarily for salaried employees, a postretirement benefit plan for selected employees and a defined contribution plan. The following tables present our consolidated net periodic benefit costs related to these plans during the three and six months ended June 30, 2010 and 2011 (in thousands):

	Three Months Ended June 30, 2010		Three Months Ended June 30, 2011	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of net periodic benefit costs:				
Service cost	$1,416	$88	$1,985	$91
Interest cost	800	203	950	260
Expected return on plan assets	(920)	—	(1,022)	—
Amortization of prior service cost (credit)	77	(212)	77	(213)
Amortization of actuarial loss	99	—	151	62
Net periodic benefit cost	$1,472	$79	$2,141	$200

	Six Months Ended June 30, 2010		Six Months Ended June 30, 2011	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of net periodic benefit costs:				
Service cost	$3,353	$176	$3,970	$182
Interest cost	1,666	406	1,899	519
Expected return on plan assets	(1,774)	—	(2,043)	—
Amortization of prior service cost (credit)	154	(425)	154	(426)
Amortization of actuarial loss	250	—	302	125
Net periodic benefit cost	$3,649	$157	$4,282	$400

Contributions estimated to be paid into the plans in 2011 are $9.4 million and $0.5 million for the pension and other postretirement benefit plans, respectively.

8. Debt

Consolidated debt at December 31, 2010 and June 30, 2011 was as follows (in thousands):

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

	December 31, 2010	June 30, 2011	Weighted-Average Interest Rate at June 30, 2011 (1)
Revolving credit facility	$15,000	$150,000	0.7%
$250.0 million of 6.45% Notes due 2014	249,786	249,814	6.3%
$250.0 million of 5.65% Notes due 2016	252,466	252,252	5.7%
$250.0 million of 6.40% Notes due 2018	259,125	262,034	5.1%
$550.0 million of 6.55% Notes due 2019	581,890	580,216	5.9%
$300.0 million of 4.25% Notes due 2021	298,932	298,974	4.3%
$250.0 million of 6.40% Notes due 2037	248,949	248,956	6.3%
Total debt	$1,906,148	$2,042,246	

(1) Weighted-average interest rate includes the impact of outstanding interest rate swaps, the amortization/accretion of discounts and premiums and the amortization/accretion of gains and losses realized on historical cash flow and fair value hedges (see Note 9—Derivative Financial Instruments for detailed information regarding our current interest rate swaps).

The face value of our debt at June 30, 2011 was $2.0 billion. The difference between the face value and carrying value of the debt outstanding is the unamortized portion of various fair value hedges and the unamortized discounts and premiums on debt issuances. Note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of the associated note.

The amounts outstanding under the notes and revolving credit facility described in the table above are senior indebtedness.

Revolving Credit Facility. The total borrowing capacity under the revolving credit facility, which matures in September 2012, was $550.0 million at June 30, 2011. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. Additionally, a commitment fee is assessed at a rate from 0.05% to 0.125%, depending on our credit ratings. Borrowings under this facility are used for general purposes, including capital expenditures. As of June 30, 2011, there was $150.0 million outstanding under this facility and $4.6 million obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets but do decrease our borrowing capacity under the facility.

9. Derivative Financial Instruments

Commodity Derivatives

Our petroleum products blending activities produce gasoline products, and we can estimate the timing and quantities of sales of these products. We use a combination of forward purchase and sales contracts, NYMEX contracts and butane price swap purchase agreements to lock in most of the product margins realized from our blending activities that we choose to hedge.

We account for the forward purchase and sales contracts we use in our blending activities as normal purchases and sales. As of June 30, 2011, we had commitments under forward purchase contracts for product purchases of approximately 0.8 million barrels that are being accounted for as normal purchases totaling approximately $77.1

million, and we had commitments under forward sales contracts for product sales of approximately 1.1 million barrels that are being accounted for as normal sales totaling approximately $138.3 million.

We use NYMEX contracts and butane price swap purchase agreements to help manage commodity price risk. We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell in future periods. Some of these NYMEX contracts qualify for hedge accounting treatment, and we designate and account for these as either cash flow or fair value hedges. We account for those NYMEX contracts that do not qualify for hedge accounting treatment as economic hedges. We use the butane price swap purchase agreements to hedge against changes in the price of butane we expect to purchase in the future. We elected to not designate the butane price swap purchase agreements we have entered into as hedges for accounting purposes because the related NYMEX contracts associated with the gasoline that will be produced and sold from these future butane purchases did not qualify for hedge accounting treatment. At June 30, 2011, we had open NYMEX contracts representing 3.9 million barrels of petroleum products we expect to sell in the future in connection with the belowlisted business activities. Additionally, we had open butane price swap agreements on the purchase of 0.3 million barrels of butane.

- Petroleum products blending and fractionation - NYMEX contracts representing 1.9 million barrels of petroleum products, of which 0.7 million barrels were designated as cash flow hedges and 1.2 million barrels that did not qualify as hedges for accounting purposes that mature between July 2011 and April 2012. The open butane swap positions noted above, which mature between September and December 2011, are also associated with our blending and fractionation activities;

- Linefill on our Houston-to-El Paso pipeline section - NYMEX contracts representing 1.0 million barrels of petroleum products that did not qualify as hedges for accounting purposes that mature between July 2011 and May 2012;

- Petroleum products pipeline over/short activity - NYMEX contracts representing 0.2 million barrels of petroleum products that did not qualify as hedges for accounting purposes that mature in July 2011; and

- Crude oil storage and pipeline:

NYMEX contracts associated with our crude oil tank bottom inventory for our Cushing storage facility representing 0.7 million barrels of crude oil, designated as fair value hedges for accounting purposes, that mature in November 2013;

NYMEX contracts associated with our crude oil pipeline linefill representing less than 0.1 million barrels of crude oil, designated as fair value hedges for accounting purposes, that mature in August 2011; and

NYMEX contracts associated with our crude oil pipeline over/short activity representing 0.1 million barrels of crude oil that did not qualify as fair value hedges for accounting purposes that mature in July 2011.

At June 30, 2011, the fair value of our open NYMEX contracts was a net liability of $18.4 million and the value of our butane butane price swap purchase agreements was a liability of $0.8 million. Combined, the net liability was $19.2 million, of which $8.2 million was recorded as energy commodity derivatives contracts and $11.0 million was recorded as other noncurrent liabilities on our consolidated balance sheet. At June 30, 2011, we had made margin deposits of $43.5 million for these contracts, which were recorded as energy commodity derivatives deposits on our consolidated balance sheet. We have the right to offset the combined fair values of our open NYMEX contracts and our open butane price swap purchase agreements against our margin deposits under a master netting arrangement with our counterparty; however, we have elected to disclose the combined fair values of our open NYMEX and butane price swap purchase agreements separately from these related margin deposits on our consolidated balance sheet. We have netted the fair values of our NYMEX agreements and butane price swap agreements together on our consolidated balance sheets.

Interest Rate Derivatives

In 2011, we entered into $100.0 million of interest rate swap agreements to hedge against changes in the fair value of a portion of our 6.40% notes due 2018. We account for these agreements as fair value hedges. These agreements effectively convert $100.0 million of our 6.40% fixed-rate notes to floating-rate debt. Under the terms of the agreements, we receive the 6.40% fixed rate of the notes and pay a weighted average rate of six-month LIBOR in arrears plus 2.75%. The agreements terminate in July 2018, which is the maturity date of the related notes. Payments settle in January and July each year. During each period, we record the impact of these swaps based on the forward LIBOR curve. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to our interest expense. These interest rate derivatives contain credit-risk-related contingent features, which provide that, in the event we default on any material obligation or in case of a merger in which our credit rating becomes "materially weaker," which would generally be interpreted as falling below investment grade, the counterparties to our interest rate derivative agreements could terminate their respective agreements and require immediate settlement. Our interest rate swap agreements were in a net asset position as of June 30, 2011.

Derivative activity included in accumulated other comprehensive loss ("AOCL") for the three and six months ended June 30, 2010 and 2011 was as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
Derivative Activity Included in AOCL	2010	2011	2010	2011
Beginning balance	$3,448	$3,284	$1,743	$3,325
Net gain (loss) on commodity hedges	—	4,613	(289)	4,613
Reclassification of net gain on cash flow hedges to interest expense	(41)	(41)	(82)	(82)
Reclassification of net loss on commodity hedges to product sales revenues	—	—	2,035	—
Ending balance	$3,407	$7,856	$3,407	$7,856

As of June 30, 2011, the net gain estimated to be classified to interest expense and product sales revenues over the next twelve months from AOCL is approximately $0.2 million and $4.6 million, respectively.

The following table provides a summary of the effect on our consolidated statements of income for the three and six months ended June 30, 2010 and 2011 of derivatives accounted for under ASC 815-25, Derivatives and Hedging—Fair Value Hedges, that were designated as hedging instruments (in thousands):

Derivative Instrument	Location of Gain Recognized on Derivative	Amount of Gain Recognized on Derivative				Amount of Interest Expense Recognized on Fixed-Rate Debt (Related Hedged Item)			
		Three Months Ended		Six Months Ended		Three Months Ended		Six Months Ended	
		June 30, 2010	June 30, 2011	June 30, 2010	June 30, 2011	June 30, 2010	June 30, 2011	June 30, 2010	June 30, 2011
Interest rate swap agreements	Interest expense	$1,588	$808	$4,604	$1,011	$(8,636)	$(4,001)	$(17,277)	$(6,223)

During 2011, we had open NYMEX contracts on 0.7 million barrels of crude oil which were designated as fair value hedges. Because there was no ineffectiveness recognized on these hedges, the unrealized losses of $11.1 million from the agreements as of June 30, 2011 were fully offset by adjustments of $11.0 million and $0.1 million to tank bottom inventory and other current assets, respectively; therefore, there was no net impact on product sales revenues.

The following is a summary of the effect on our consolidated statements of income for the three and six months ended June 30, 2010 and 2011 of the effective portion of derivatives accounted for under ASC 815-30, Derivatives and Hedging—Cash Flow Hedges, that were designated as hedging instruments (in thousands). See Note 4 - Product Sales Revenues for further details regarding the impact of our NYMEX agreements on product sales.

	Three Months Ended June 30, 2010		
	Effective Portion		
Derivative Instrument	Amount of Gain Recognized in AOCL on Derivative	Location of Gain Reclassified from AOCL into Income	Amount of Gain Reclassified from AOCL into Income
Interest rate swap agreements	$—	Interest expense	$41

Three Months Ended June 30, 2011
Effective Portion

Derivative Instrument	Amount of Gain Recognized in AOCL on Derivative	Location of Gain Reclassified from AOCL into Income	Amount of Gain Reclassified from AOCL into Income
Interest rate swap agreements	$—	Interest expense	$41
NYMEX commodity contracts	4,613	Product sales revenues	—
Total cash flow hedges	$4,613	Total	$41

	Six Months Ended June 30, 2010		
	Effective Portion		
Derivative Instrument	Amount of Gain (Loss) Recognized in AOCL on Derivative	Location of Gain (Loss) Reclassified from AOCL into Income	Amount of Gain (Loss) Reclassified from AOCL into Income
Interest rate swap agreements	$—	Interest expense	$82
NYMEX commodity contracts	(289)	Product sales revenues	(2,035)
Total cash flow hedges	$(289)	Total	$(1,953)

	Six Months Ended June 30, 2011		
	Effective Portion		
Derivative Instrument	Amount of Gain Recognized in AOCL on Derivative	Location of Gain Reclassified from AOCL into Income	Amount of Gain Reclassified from AOCL into Income
Interest rate swap agreements	$—	Interest expense	$82
NYMEX commodity contracts	4,613	Product sales revenues	—
Total cash flow hedges	$4,613	Total	$82

There was no ineffectiveness recognized for any of our cash flow or fair value hedges during the three and six months ended June 30, 2010 or 2011.

The following table provides a summary of the effect on our consolidated statements of income for the three and six months ended June 30, 2010 and 2011 of derivatives accounted for under ASC 815-10-35; Derivatives and Hedging—Overall—Subsequent Measurement, that were not designated as hedging instruments (in thousands):

		Amount of Gain (Loss) Recognized on Derivative			
		Three Months Ended June 30,		Six Months Ended June 30,	
Derivative Instrument	Location of Gain (Loss) Recognized on Derivative	2010	2011	2010	2011
NYMEX commodity contracts	Product sales revenues	$23,766	$2,150	$16,832	$(36,183)
Butane price swap purchase contracts	Product purchases	—	(839)	—	(839)
	Total	$23,766	$1,311	$16,832	$(37,022)

The following tables provide a summary of the amounts included on our consolidated balance sheets of the fair value of derivatives accounted for under ASC 815, Derivatives and Hedging, that were designated as hedging instruments as of December 31, 2010 and June 30, 2011 (in thousands):

	December 31, 2010			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Other noncurrent assets	$—	Other noncurrent liabilities	$4,920

	June 30, 2011			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Interest rate swap agreement, current portion	Other current assets	$2,678	Other current liabilities	$—

Interest rate swap agreement, noncurrent portion	Other noncurrent assets	1,849	Other noncurrent liabilities	—
NYMEX commodity contracts	Energy commodity derivatives contracts	2,209	Energy commodity derivatives contracts	107
NYMEX commodity contracts	Other noncurrent assets	—	Other noncurrent liabilities	10,962
	Total	$6,736	Total	$11,069

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables provide a summary of the amounts included on our consolidated balance sheets of the fair value of derivatives accounted for under ASC 815, Derivatives and Hedging, that were not designated as hedging instruments as of December 31, 2010 and June 30, 2011 (in thousands):

	December 31, 2010			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts	$—	Energy commodity derivatives contracts	$11,790

	June 30, 2011			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts	$5,191	Energy commodity derivatives contracts	$14,634
Butane price swap purchase contracts	Energy commodity derivatives contracts	—	Energy commodity derivatives contracts	839
	Total	$5,191	Total	$15,473

10. Commitments and Contingencies

Clean Air Act - Section 185 Liability.

Section 185 of the Clean Air Act ("CAA 185") requires states to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas if the designated area within the state did not meet its attainment deadline. Imposition of the fee is mandated for each calendar year after the attainment date until the area is redesignated as an attainment area for ozone. The Environmental Protection Agency ("EPA") is required to collect the fees if a state does not meet the requirements of or if a state is not administering and enforcing CAA 185. The Houston-Galveston region was initially determined to be a severe nonattainment area that did not meet its 2007 attainment deadline and, as such, would be subject to CAA 185. The Texas Commission on Environmental Quality (“TCEQ”) drafted a “Failure to Attain Rule” (the “Rule”) to implement the requirements of CAA 185. The Rule was scheduled to be final in the spring of 2010 and would have provided for the collection of an annual failure to attain fee for emissions from calendar year 2008 forward. We have certain facilities in the Houston area that would have been subject to the TCEQ's Rule.

Under the Rule, the annual fees to be paid by entities within the Houston-Galveston non-attainment area would have been determined by the emissions from a facility that exceed the established baseline. In January 2010, the EPA issued guidance for states developing fee programs under CAA 185. In response to and based on the standards in the EPA's guidance, the TCEQ suspended the draft Rule and submitted a request for a determination by the EPA (a "Termination Determination") that the Houston-Galveston Region no longer qualified as a severe non-attainment area. If TCEQ's request for a Termination Determination were approved by the EPA, the requirement to assess a CAA 185 fee would be terminated. Subsequent to the TCEQ's request for a Termination Determination, the Natural Resource Defense Counsel submitted a petition in federal court challenging the legality of the EPA's guidance. Based upon the EPA's belief and assertion that the guidance would be sustained in federal court, management determined the probability of the assessment of an annual fee for the Houston-Galveston area was remote.

On July 1, 2011, the court issued an opinion in the National Resource Defense Counsel case vacating the EPA's January 2010 guidance memorandum on state's CAA 185 equivalent programs. As a result of the court's ruling, the EPA has instructed the TCEQ that it is unable to approve the Termination Determination request. In addition, the Sierra Club filed a Clean Air Act citizen suit in 2010, Sierra Club v. Jackson, seeking to compel the EPA to collect CAA 185 fees in the Houston-Galveston area.

Based on the recent court decisions and statements by the EPA, management now believes that it is probable that the TCEQ will move forward with its CAA 185 rule making process. A number of potential alternative outcomes exist, including the possibility that we will not be assessed any CAA 185 fees. However, management now believes it is probable we will be assessed fees for excess emissions at our Houston area facilities for the years following 2007 and estimates that the range of fees that could be assessed to us to be between $6.4 million and $13.7 million. We have recorded an accrual of $6.4 million related to this matter, of which $4.8 million was recorded as a current environmental liability and $1.6 million was recorded as a long-term environmental liability.

Environmental Liabilities.

Liabilities recognized for estimated environmental costs were $32.8 million and $39.6 million at December 31, 2010 and June 30, 2011, respectively. We have classified environmental liabilities as current or noncurrent based on management's estimates regarding the timing of actual payments. Management estimates that expenditures associated with these environmental liabilities will be paid over the next 10 years. Environmental expenses recognized as a result of changes in our environmental liabilities are included in operating expenses on our consolidated statements of income. Environmental expense was $2.7 million and $5.1 million for the three and six months ended June 30, 2010, respectively, and $8.6 million and $12.5 million for the three and six months ended June 30, 2011, respectively, including environmental expense recognized in second-quarter 2011 for the Section 185 contingent liability accrual discussed above.

Environmental Receivables.

Receivables from insurance carriers related to environmental matters at December 31, 2010 were $2.2 million, of which $1.0 million and $1.2 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheets. Receivables from insurance carriers related to environmental matters at June 30, 2011 were $2.0 million, of which $0.3 million and $1.7 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheets.

Unrecognized Product Gains.

Our petroleum terminals operations generate product overages and shortages that result from metering inaccuracies and product evaporation, expansion, releases and contamination. Most of the contracts we have with our customers state that we bear the risk of loss (or gain) from these conditions. When our petroleum terminals experience net product shortages, we recognize expense for those losses in the periods in which they occur. When our petroleum 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 net unrecognized product overages for our petroleum terminals operations had a market value of approximately $1.8 million as of June 30, 2011. 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 net future product shortages.

Other.

We are a party to various other claims, legal actions and complaints arising in the ordinary course of business. While the results cannot be predicted with certainty, management believes 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 financial position, results of operations or cash flows.

11. Long-Term Incentive Plan

We have a long-term incentive plan ("LTIP") for certain of our employees and for directors of our general partner. The LTIP primarily consists of phantom units and, as of June 30, 2011, permits the grant of awards covering an aggregate of 4.7 million of our limited partner units. The remaining units available under the LTIP at June 30, 2011 total 1.6 million. The compensation committee of our general partner's board of directors administers the LTIP.

Our equity-based incentive compensation expense was as follows (in thousands):

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Three Months Ended June 30, 2010			Six Months Ended June 30, 2010		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
2007 awards	$—	$—	$—	$—	$6	$6
2008 awards	462	163	625	2,925	1,269	4,194
2009 awards	350	186	536	700	460	1,160
2010 awards	453	128	581	909	258	1,167
Retention awards	208	—	208	382	—	382
Total	$1,473	$477	$1,950	$4,916	$1,993	$6,909

	Three Months Ended June 30, 2011			Six Months Ended June 30, 2011		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
2009 awards	$2,308	$1,583	$3,891	$3,235	$2,205	$5,440
2010 awards	387	165	552	1,337	519	1,856
2011 awards	562	144	706	1,124	289	1,413
Retention awards	118	—	118	308	—	308
Total	$3,375	$1,892	$5,267	$6,004	$3,013	$9,017

In January 2011, the cumulative amounts of the 2008 LTIP awards were settled by issuing 252,746 limited partner units and distributing those units to the LTIP participants. The minimum tax withholdings associated with this settlement and employer taxes of $7.4 million and $0.9 million, respectively, were paid in January 2011.

In January 2011, the compensation committee of our general partner's board of directors approved 148,670 phantom unit awards pursuant to our LTIP. These awards have a three-year vesting period that will end on December 31, 2013.

12. Distributions

Distributions we paid during 2010 and 2011 were as follows (in thousands, except per unit amounts):

Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution to Limited Partners
2/12/2010	$0.7100	$75,779
5/14/2010	0.7200	76,847
Through 6/30/2010	1.4300	152,626
8/13/2010	0.7325	82,393
11/12/2010	0.7450	83,798
Total	$2.9075	$318,817
2/14/2011	$0.7575	$85,398
5/13/2011	0.7700	86,807
Through 6/30/2011	1.5275	172,205
8/12/2011[a]	0.7850	88,498

Total	$2.3125	$260,703

(a) Our general partner's board of directors declared this cash distribution on July 21, 2011 to be paid on August 12, 2011 to unitholders of record at the close of business on August 4, 2011.

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

13. Fair Value

Fair Value of Financial Instruments

We used the following methods and assumptions in estimating our fair value disclosure for financial instruments:

- Cash and cash equivalents and restricted cash. The carrying amounts reported on our consolidated balance sheets approximate fair value due to the short-term maturity or variable rates of these instruments.
- Energy commodity derivatives deposits. This asset represents short-term deposits we paid associated with our energy commodity derivatives contracts. The carrying amount reported on our consolidated balance sheets approximates fair value as the deposits paid change daily in relation to the associated contracts.
- Long-term receivables. Fair value was determined by estimating the present value of future cash flows using a risk-free rate of interest.
- Energy commodity derivatives contracts. These include NYMEX and butane price swap purchase agreements related to petroleum products. These contracts are carried at fair value on our consolidated balance sheets and are valued based on quoted prices in active markets. See Note 9 - Derivative Financial Instruments for further disclosures regarding these contracts.
- Debt. The fair value of our publicly traded notes, excluding the value of interest rate swaps qualifying as fair value hedges, was based on the prices of those notes at December 31, 2010 and June 30, 2011. The carrying amount of borrowings under our revolving credit facility approximates fair value due to the variable rates of that instrument.
- Interest rate swaps. Fair value was determined based on an assumed exchange, at the end of each period, in an orderly transaction with market participants using market observable interest rate swap curves (see Note 9 – Derivative Financial Instruments). The exchange value was calculated using present value techniques on estimated future cash flows based on forward interest rate curves.

The following table reflects the carrying amounts and fair values of our financial instruments as of December 31, 2010 and June 30, 2011 (in thousands):

	December 31, 2010		June 30, 2011	
Assets (Liabilities)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$7,483	$7,483	$12,992	$12,992
Restricted cash	$14,379	$14,379	$—	$—
Energy commodity derivatives deposits	$22,302	$22,302	$43,505	$43,505
Long-term receivables	$1,167	$1,161	$1,710	$1,705
Energy commodity derivatives contracts (current)	$(11,790)	$(11,790)	$(8,180)	$(8,180)
Energy commodity derivatives contracts (noncurrent)	$(4,920)	$(4,920)	$(10,962)	$(10,962)
Debt	$(1,906,148)	$(2,048,895)	$(2,042,246)	$(2,247,520)
Interest rate swaps (current)	$—	$—	$2,678	$2,678
Interest rate swaps (noncurrent)	$—	$—	$1,849	$1,849

Fair Value Measurements

The following tables summarize the recurring fair value measurements of our NYMEX commodity contracts and interest rate swaps as of December 31, 2010 and June 30, 2011, based on the three levels established by ASC 820-10-50; Fair Value Measurements and Disclosures—Overall—Disclosure (in thousands):

Assets (Liabilities)		Fair Value Measurements as of December 31, 2010 using:		
	Total	Quoted Prices in Active Markets for Identical	Significant Other Observable	Significant Unobservable Inputs

		Assets (Level 1)	Inputs (Level 2)	(Level 3)
Energy commodity derivatives contracts (current)	$(11,790)	$(11,790)	$—	$—
Energy commodity derivatives contracts (noncurrent)	$(4,920)	$(4,920)	$—	$—

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

Assets (Liabilities)	Total	Fair Value Measurements as of June 30, 2011 using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivatives contracts (current)	$(8,180)	$(8,180)	$—	$—
Energy commodity derivatives contracts (noncurrent)	$(10,962)	$(10,962)	$—	$—
Interest rate swaps (current)	$2,678	$—	$2,678	$—
Interest rate swaps (noncurrent)	$1,849	$—	$1,849	$—

14. Subsequent Events

Recognizable events

No recognizable events occurred during the period.

Non-recognizable events

In July 2011, our general partner's board of directors declared a quarterly distribution of $0.785 per unit to be paid on August 12, 2011 to unitholders of record at the close of business on August 4, 2011. The total cash distributions to be paid are $88.5 million (see Note 12—Distributions for details).

In July 2011, Lonny E. Townsend, Senior Vice President, General Counsel, Compliance and Ethics Officer and Assistant Secretary of Magellan GP, LLC, our general partner, informed the Board of Directors of our general partner (the "Board of Directors") that he will retire from his positions effective January 2, 2012. The Board of Directors then elected Douglas J. May to succeed Mr. Townsend in these same positions. Upon Mr. Townsend's retirement, Mr. May will become Senior Vice President, General Counsel, Compliance and Ethics Officer and Assistant Secretary of our general partner.

As part of the annual review of various executive compensation and benefit plans by the Compensation Committee of the Board of Directors, and in a continuing effort to remain competitive with peer companies and retain our executive officers, in July 2011, the Board of Directors adopted the Magellan Midstream Holdings GP, LLC Executive Severance Pay Plan (the "Plan"). Under the Plan, severance benefits will be paid to our executive officers based on years of service for the following termination events:

- Position Elimination — Benefits payable to executive officers will be two weeks base salary for each completed year of service. Base salary excludes any incentive compensation. This benefit is consistent with the benefit all employees receive under our existing severance pay plan.

- Change-in-Control — As defined in the Plan, to receive severance pay benefits due to a change-in-control, the executive officer must resign voluntarily for good reason or be terminated involuntarily for other than performance reasons within two years following a change-in-control. Benefits payable to the chief executive officer are three times annual base salary plus current year's target annual incentive plan payout. Benefits payable to other executive officers are two times annual base salary plus current year's target annual incentive plan payout.

In July 2011, we terminated and settled the $100.0 million of swaps and received $6.1 million, which was recorded as an adjustment to long-term debt and will be amortized over the remaining life of the 6.40% notes.

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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, such as gasoline and diesel fuel, and crude oil. As of June 30, 2011, our three operating segments included:

- petroleum pipeline system, comprised of approximately 9,600 miles of pipeline and 51 terminals;
- petroleum terminals, which includes storage terminal facilities (consisting of six marine terminals located along coastal waterways and crude oil storage in Cushing, Oklahoma) and 27 inland terminals; and
- ammonia pipeline system, representing our 1,100-mile ammonia pipeline and six associated terminals.

The following discussion provides an analysis of the results for each of our operating segments, an overview of our liquidity and capital resources and other items related to our 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, 2010.

Recent Developments

Changes in our Executive Officers. In July 2011, Lonny E. Townsend, Senior Vice President, General Counsel, Compliance and Ethics Officer and Assistant Secretary of Magellan GP, LLC, our general partner, informed the Board of Directors of our general partner (the "Board of Directors") that he will retire from his positions effective January 2, 2012. The Board of Directors then elected Douglas J. May to succeed Mr. Townsend in these same positions upon Mr. Townsend's retirement.

Acquisitions. In April 2011, we acquired an approximate 38-mile petroleum products pipeline segment connected to our petroleum pipeline system at Reagan, Texas and in May 2011, we acquired petroleum products storage tanks in Riverside, Missouri. Collectively, we paid $10.4 million for these acquisitions. The operating results of these assets have been included in our petroleum pipeline system segment from the acquisition date.

Cash Distribution. On July 21, 2011, the Board of Directors declared a quarterly cash distribution of $0.785 per unit for the period of April 1, 2011 through June 30, 2011. This quarterly cash distribution will be paid on August 12, 2011 to unitholders of record on August 4, 2011. Total distributions to be paid under this declaration are approximately $88.5 million.

Executive Officer Severance Pay Plan. As part of the annual review of various executive compensation and benefit plans by the Compensation Committee of the Board of Directors, and in a continuing effort to remain competitive with peer companies and retain our executive officers, in July 2011, the Board of Directors adopted the Magellan Midstream Holdings GP, LLC Executive Severance Pay Plan (the "Plan"). Under the Plan, severance benefits will be paid to our executive officers based on years of service for the following termination events:

- Position Elimination — Benefits payable to executive officers will be two weeks base salary for each completed year of service. Base salary excludes any incentive compensation. This benefit is consistent with the benefit all employees receive under our existing severance pay plan.
-

Change-in-Control — As defined in the Plan, to receive severance pay benefits due to a change-in-control, the executive officer must resign voluntarily for good reason or be terminated involuntarily for other than performance reasons within two years following a change-in-control. Benefits payable to the chief executive officer are three times annual base salary plus current year's target annual incentive plan payout. Benefits payable to other executive officers are two times annual base salary plus current year's target annual incentive plan payout.

Interest Rate Swap Settlement. In July 2011, we terminated and settled the $100.0 million of swaps and received $6.1 million, which was recorded as an adjustment to long-term debt and will be amortized over the remaining life of the 6.40% notes.

Results of Operations

We believe that investors benefit from having access to the same financial measures utilized by management. Operating

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margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. Operating margin is not a generally accepted accounting principles ("GAAP") measure, but the components of operating margin are computed 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 following tables. Operating profit includes expense items, such as depreciation and amortization expense and general and administrative ("G&A") expenses, which management does not consider when evaluating the core profitability of our operations. Additionally, product margin, which management primarily uses to evaluate the profitability of our commodity-related activities, is provided in these tables. Product margin is a non-GAAP measure; however, its components of product sales and product purchases are determined in accordance with GAAP.

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Three Months Ended June 30, 2010 Compared to Three Months Ended June 30, 2011

	Three Months Ended June 30,		Variance Favorable (Unfavorable)	
	2010	2011	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$141.5	$161.1	$19.6	14
Petroleum terminals	48.4	57.0	8.6	18
Ammonia pipeline system	3.8	5.8	2.0	53
Intersegment eliminations	(0.6)	(0.7)	(0.1)	(17)
Total transportation and terminals revenues	193.1	223.2	30.1	16
Affiliate management fee revenue	0.2	0.2	—	—
Operating expenses:				
Petroleum pipeline system	49.4	51.7	(2.3)	(5)
Petroleum terminals	18.2	26.6	(8.4)	(46)
Ammonia pipeline system	3.2	3.8	(0.6)	(19)
Intersegment eliminations	(0.6)	(0.8)	0.2	33
Total operating expenses	70.2	81.3	(11.1)	(16)
Product margin:				
Product sales revenues	229.6	159.9	(69.7)	(30)
Product purchases	183.6	118.8	64.8	35
Product margin	46.0	41.1	(4.9)	(11)
Equity earnings	1.5	1.4	(0.1)	(7)
Operating margin	170.6	184.6	14.0	8
Depreciation and amortization expense	25.7	30.6	(4.9)	(19)
G&A expense	20.2	25.3	(5.1)	(25)
Operating profit	124.7	128.7	4.0	3
Interest expense (net of interest income and interest capitalized)	21.7	24.8	(3.1)	(14)
Debt placement fee amortization expense	0.4	0.4	—	—
Income before provision for income taxes	102.6	103.5	0.9	1
Provision for income taxes	0.1	0.5	(0.4)	(400)
Net income	$102.5	$103.0	$0.5	—
Operating Statistics:				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.304	$1.097		
Volume shipped (million barrels):				
Refined products:				
Gasoline	42.8	52.3		
Distillates	28.8	32.9		
Aviation fuel	5.2	7.7		
Liquefied petroleum gases	1.9	2.2		
Crude oil	—	10.2		
Total volume shipped	78.7	105.3		
Petroleum terminals:				

Storage terminal average utilization (million barrels per month)	23.8	31.1
Inland terminal throughput (million barrels)	30.3	29.3
Ammonia pipeline system:		
Volume shipped (thousand tons)	111	191

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Transportation and terminals revenues increased $30.1 million, resulting from:

- an increase in petroleum pipeline system revenues of $19.6 million. The Houston, Texas-area pipelines we purchased in September 2010 contributed $7.1 million to revenues in the current quarter and transportation volumes of 23.1 million barrels. Excluding the impact of this acquisition, revenues increased $12.5 million primarily attributable to higher transportation revenues resulting from:

a 5% increase in volumes driven primarily by new customer commitments; and

a 3% increase in the average per barrel tariff rate, going from $1.304 per barrel to $1.341.

Additionally, increased demand for pipeline capacity leases and higher storage lease revenues and incremental fees for terminal throughput, ethanol and other blending services contributed to the increase in revenues;

- an increase in petroleum terminals revenues of $8.6 million, of which over 60% was contributed by the Cushing, Oklahoma storage assets acquired in September 2010. Excluding this acquisition, revenues increased at our other storage and inland terminals. Storage terminal revenues increased principally due to higher rates on existing storage contracts and from additional leases of new tanks placed in service. Inland revenues benefited from higher fees for ethanol blending; and
- an increase in ammonia pipeline system revenues of $2.0 million. Our pipeline was unavailable for shipments during much of second quarter 2010 due to hydrostatic testing on the system.

Operating expenses increased $11.1 million, resulting from:

- an increase in petroleum pipeline system expenses of $2.3 million primarily resulting from a $2.8 million impairment charge for a system terminal we plan to close in 2011. Otherwise, increases in asset integrity and power costs and an accrual recognized in the current quarter related to contingent air emission fees were more than offset by more favorable product overages (which reduce operating expenses);
- an increase in petroleum terminals expenses of $8.4 million, of which $1.3 million was attributable to the Cushing storage assets acquired in September 2010. Excluding these costs, operating expenses increased $7.1 million primarily related to an accrual recognized in the current quarter for contingent air emission fees and higher losses on asset retirements resulting from the demolition of older tanks to make room for new tank construction; and
- an increase in ammonia pipeline system expenses of $0.6 million due primarily to higher power costs resulting from additional volumes.

Product sales revenues primarily resulted from our petroleum products blending activities, product marketing and linefill management associated with our Houston-to-El Paso pipeline section, terminal product gains and transmix fractionation. We utilize New York Mercantile Exchange (“NYMEX”) contracts to hedge against changes in the price of petroleum products we expect to sell in the future. The period change in the mark-to-market value of these contracts that are not designated as hedges for accounting purposes, the effective portion of the change in value of matured NYMEX contracts that qualified for hedge accounting treatment and any ineffectiveness of NYMEX contracts that qualify for hedge accounting treatment are also included in product sales revenues. We use butane price swap agreements to hedge against changes in the price of petroleum products we expect to purchase in future periods. The period change in the mark-to-market value of these swap agreements, which were not designated as hedges, are included as adjustments to product purchases. Product margin decreased $4.9 million between periods due primarily to lower profits from our petroleum products blending activities and higher unrealized losses from NYMEX contracts, partially offset by higher profits from our fractionation activities.

Depreciation and amortization expense increased $4.9 million primarily due to expansion capital projects placed into service and recent acquisitions.

G&A expense increased $5.1 million primarily due to higher equity-based incentive compensation expense. Equity-based incentive compensation expense increased principally because, during the current quarter, we increased the 2009 incentive award accruals to the stretch payout amount based on our strong performance against the financial metric associated with those awards. Increases to the 2010 equity-based incentive compensation expense accruals for above-target payouts related to the 2008 incentive awards were not recognized until the third and fourth quarters of 2010.

Interest expense, net of interest income and interest capitalized, increased $3.1 million. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $2.0 billion for second quarter 2011 from $1.7 billion for second quarter 2010 principally due to borrowings for expansion capital expenditures and acquisitions. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, increased to 5.3% in second

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quarter 2011 from 5.1% in second quarter 2010.

Six Months Ended June 30, 2010 Compared to Six Months Ended June 30, 2011

	Six Months Ended June 30,		Variance Favorable (Unfavorable)	
	2010	2011	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$264.4	$305.2	$40.8	15
Petroleum terminals	94.1	112.2	18.1	19
Ammonia pipeline system	8.9	12.8	3.9	44
Intersegment eliminations	(1.1)	(1.6)	(0.5)	(45)
Total transportation and terminals revenues	366.3	428.6	62.3	17
Affiliate management fee revenue	0.4	0.4	—	—
Operating expenses:				
Petroleum pipeline system	92.3	89.4	2.9	3
Petroleum terminals	34.6	48.6	(14.0)	(40)
Ammonia pipeline system	7.2	7.1	0.1	1
Intersegment eliminations	(1.7)	(1.4)	(0.3)	(18)
Total operating expenses	132.4	143.7	(11.3)	(9)
Product margin:				
Product sales revenues	386.0	397.2	11.2	3
Product purchases	316.5	330.0	(13.5)	(4)
Product margin	69.5	67.2	(2.3)	(3)
Equity earnings	2.7	2.8	0.1	4
Operating margin	306.5	355.3	48.8	16
Depreciation and amortization expense	52.1	60.0	(7.9)	(15)
G&A expense	43.4	49.9	(6.5)	(15)
Operating profit	211.0	245.4	34.4	16
Interest expense (net of interest income and interest capitalized)	42.6	50.6	(8.0)	(19)
Debt placement fee amortization expense	0.7	0.8	(0.1)	(14)
Income before provision for income taxes	167.7	194.0	26.3	16
Provision for income taxes	0.7	0.9	(0.2)	(29)
Net income	$167.0	$193.1	$26.1	16
Operating Statistics:				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.265	$1.071		
Volume shipped (million barrels):				
Refined products:				
Gasoline	82.1	104.7		
Distillates	53.2	62.5		
Aviation fuel	10.0	12.8		
Liquefied petroleum gases	3.1	3.1		
Crude oil	—	17.2		
Total volume shipped	148.4	200.3		

Petroleum terminals:		
Storage terminal average utilization (million barrels per month)	23.8	30.5
Inland terminal throughput (million barrels)	56.4	56.9
Ammonia pipeline system:		
Volume shipped (thousand tons)	278	412

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Transportation and terminals revenues increased $62.3 million, resulting from:

- an increase in petroleum pipeline system revenues of $40.8 million. The Houston, Texas-area pipelines we purchased in September 2010 contributed $13.8 million to revenues in the current year and transportation volumes of 42.4 million barrels. Excluding the impact of this acquisition, revenues increased $27.0 million primarily attributable to higher transportation revenues resulting from:

  a 6% increase in transportation volumes driven by new customer commitments; and

  a 2% increase in the average per barrel tariff rate, going from $1.265 per barrel to $1.293.

  Additionally, higher storage lease revenues and incremental fees for terminal throughput, ethanol and other blending contributed to the increase in revenues;

- an increase in petroleum terminals revenues of $18.1 million, of which more than half was contributed by the Cushing, Oklahoma storage assets acquired in September 2010. Excluding this acquisition, revenues increased at our other storage and inland terminals. Storage terminal revenues increased principally due to higher rates on existing storage contracts and from additional leases of new tanks placed in service. Inland revenues benefited from higher fees due to ethanol and additive blending; and

- an increase in ammonia pipeline system revenues of $3.9 million due to increased shipments during 2011. Our pipeline was unavailable for shipments during much of 2010 due to hydrostatic testing being performed on the pipeline.

Operating expenses increased $11.3 million, resulting from:

- a decrease in petroleum pipeline system expenses of $2.9 million. Pipeline system expenses decreased $4.5 million related to our September 2010 pipeline purchase because favorable product overages (which reduce operating expenses) more than offset other operating expenses. Excluding this reduction, petroleum pipeline expenses increased $1.6 million due largely to a $2.8 million asset impairment recognized in the current quarter. Otherwise, higher losses from asset replacements, increases in power costs due to increased pipeline volumes, higher compensation costs, an accrual recognized in the current period related to contingent air emission fees and higher property taxes were more than offset by more favorable product overages;
- an increase in petroleum terminals expenses of $14.0 million, of which $2.8 million was attributable to the Cushing storage assets acquired in September 2010. Excluding these costs, operating expenses increased $11.2 million primarily related to an accrual recognized in the current period for contingent air emission fees, higher environmental expenses, product downgrade charges in the 2011 period and higher losses on asset retirements resulting from the demolition of older tanks to make room for new tank construction; and
- a decrease in ammonia pipeline system expenses of $0.1 million resulting primarily from lower asset integrity and environmental costs, partially offset by lower gains on asset sales. The 2010 period included a gain on the sale of a portion of pipeline linefill (pipeline linefill for our ammonia system is recorded as property, plant and equipment).

Product sales revenues primarily result from our petroleum products blending activities, product marketing and linefill management associated with our Houston-to-El Paso pipeline section, terminal product gains and transmix fractionation. We utilize NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell in the future related to these activities. The period change in the mark-to-market value of these contracts that do not qualify for hedge accounting treatment, the effective portion of the change in value of matured NYMEX contracts that qualified for hedge accounting treatment and any ineffectiveness of NYMEX contracts that qualify for hedge accounting treatment are also included in product sales revenues. We use butane price swap agreements to hedge against changes in the price of petroleum products we expect to purchase in future periods. The period change in the mark-to-market value of these swap agreements, which were not designated as hedges, are included as adjustments to product purchases. Product margin decreased $2.3 million between periods due primarily to higher unrealized losses on NYMEX contracts and lower profits from our petroleum products blending activities, partially offset by higher profits from our fractionation activities and the sale of more terminal product overages at higher prices.

Depreciation and amortization expense increased $7.9 million primarily due to expansion capital projects placed into service and recent acquisitions.

G&A expense increased $6.5 million primarily due to higher equity-based incentive compensation expense. Equity-based incentive compensation expense increased principally because, during the current quarter, we increased the 2009 incentive award accruals to the stretch payout amount based on our strong performance against the financial metric associated with those awards. Increases to the 2010 equity-based incentive compensation expense accruals for above-target payouts related to the 2008 incentive awards were not recognized until the third and fourth quarters of 2010.

Interest expense, net of interest income and interest capitalized, increased $8.0 million. Our average debt outstanding, excluding fair value adjustments for interest rate hedges, increased to $1.9 billion for 2011 from $1.7 billion for 2010 principally due to borrowings for expansion capital expenditures and acquisitions. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, increased to 5.4% in 2011 from 5.1% in 2010.

Liquidity and Capital Resources

Distributable Cash Flow

Distributable cash flow is a non-GAAP measure that management uses to evaluate our ability to generate cash for distribution to our limited partners. Management also uses this measure as a basis for recommending to the Board of Directors the amount of cash distributions to be paid each period. We believe that investors benefit from having access to the same financial measures utilized by management for these evaluations. A reconciliation of distributable cash flow for the six months ended June 30, 2010 and 2011 to net income, which is its nearest comparable GAAP financial measure, was as follows (in thousands):

	Six Months Ended June 30,		Increase
	2010	2011	(Decrease)
Net income	$166,986	$193,064	$26,078
Add:			
Depreciation and amortization(1)	52,714	60,797	8,083
Equity-based incentive compensation expense(2)	3,509	1,600	(1,909)
Asset retirements and impairments	(1,281)	7,106	8,387
Commodity-related adjustments:			
Derivative losses (gains) recognized in the period associated with future product transactions(3)	(13,209)	8,765	21,974
Derivative losses recognized in previous periods associated with products sold in the period(4)	(7,158)	(12,007)	(4,849)
Lower-of-cost-or-market adjustments	5,182	—	(5,182)
Houston-to-El Paso cost of sales adjustments(5)	(4,233)	(3,915)	318
Total commodity-related adjustments	(19,418)	(7,157)	12,261
Less:			
Maintenance capital	15,023	19,370	(4,347)
Other	1,579	739	840
Distributable cash flow	$185,908	$235,301	$49,393

(1) Depreciation and amortization includes debt placement fee amortization.

(2) Because we intend to satisfy vesting of units under our equity-based incentive compensation program with the issuance of limited partner units, expenses related to this program generally are deemed non-cash and added back for distributable cash flow purposes. Total equity-based incentive compensation expense for the six months ended June 30, 2010 and 2011 was $6.9 million and $9.0 million, respectively. However, the figures above include an adjustment

for minimum statutory tax withholdings we paid in 2010 and 2011 of $3.4 million and $7.4 million, respectively, for equity-based incentive compensation units that vested on the previous year end, which reduce distributable cash flow.
(3) Derivatives we use as economic hedges have not been designated as hedges for accounting purposes. These amounts represent the gains or losses of these economic hedges recognized in our earnings for products that had not physically sold as of the period end date.
(4) When we physically sell products that are economically hedged (but were not designated as hedges for accounting purposes), we include in our distributable cash flow calculations the full amount of the change in fair value of the associated derivative agreement.
(5) Cost of goods sold adjustment related to transitional commodity activities for our Houston-to-El Paso pipeline to more closely resemble current market prices for distributable cash flow purposes rather than average inventory costing as used to determine our results of operations.

Distributable cash flow increased $49.4 million. The change in net income and depreciation and amortization is discussed in detail in Results of Operations above. Cash from equity-based incentive compensation decreased primarily because the settlement of the equity-based unit awards in 2011 was higher than in 2010 and the corresponding tax withholdings we paid on those awards was higher in the current period. Asset retirements in the 2010 period included a $3.0 million insurance settlement and the gain from that settlement was excluded from our distributable cash flow. The 2011 amounts included an impairment expense of $2.8 million. The increase in cash flows from commodity-related adjustments is primarily due to the impact of price decreases during the 2010 period and price increases during the 2011 period. A discussion of our maintenance capital expenditures is provided in Capital Requirements below.

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $213.3 million and $218.1 million for the six months ended June 30, 2010 and 2011, respectively. The $4.8 million increase from 2010 to 2011 was primarily attributable to:

- a $42.5 million increase in net income, excluding the increases in non-cash depreciation and amortization expense and loss (gain) on sale, retirement and impairment of assets;
- a $14.4 million increase due to the elimination of restricted cash resulting from our purchase of the private investment group's common equity in Magellan Crude Oil, LLC ("MCO") during first quarter 2011. Prior to this, MCO's cash on hand was unavailable to us for our partnership matters and was recorded as restricted cash on our consolidated balance sheet at December 31, 2010; and
- a $10.8 million increase resulting from a $6.9 million increase in current and noncurrent environmental liabilities in 2011 versus a $3.9 million decrease in current and noncurrent environmental liabilities in 2010 primarily due to our CAA 185 contingent liability accrual (see Environmental below for further details regarding this matter) during 2011; and

These increases were partially offset by:

- a $53.8 million decrease primarily resulting from the impact of higher product prices and higher levels of inventory purchases in 2011 as compared to 2010; specifically, a $69.6 million increase in inventory in 2011 versus a $15.8 million increase in inventory in 2010; and
- an $11.7 million decrease resulting from a $14.2 million decrease in energy commodity derivatives contracts, net of increased derivatives deposits in 2011, versus a $2.5 million increase in 2010 primarily due to an increase in the number of NYMEX commodity contracts during 2011.

Net cash used by investing activities for the six months ended June 30, 2010 and 2011 was $118.2 million and $156.9 million, respectively. During 2011, we spent $95.3 million for capital expenditures, which included $19.4 million for maintenance capital and $75.9 million for expansion capital. Also during 2011, we acquired a private investment group's common equity in MCO for $40.5 million and spent $17.8 million on various asset acquisitions. During 2010, we spent $97.9 million for capital expenditures, which included $15.0 million for maintenance capital, excluding $0.5 million of maintenance capital spending to be reimbursed by insurance, and $82.4 million for expansion capital. In addition, during 2010 we acquired petroleum products storage tanks at various locations on our petroleum pipeline system for $29.3 million. Also, during 2010, proceeds from the sale of assets were $5.1 million, including $3.0 million of proceeds from the settlement of our insurance claim related to a tank fire at one of our petroleum pipeline system terminals.

Net cash used by financing activities for the six months ended June 30, 2010 and 2011 was $64.2 million and $55.7 million, respectively. During 2011, we paid cash distributions of $172.2 million to our unitholders while net borrowings on our revolving credit facility, primarily to finance expansion capital projects and the MCO buyout noted above, were $135.0 million. During 2010, we paid cash distributions of $152.6 million to our unitholders while net borrowings on our revolving credit facility, primarily to finance expansion capital projects, were $83.4 million. Additionally, we received $9.6 million from the settlement of our interest rate swap agreements during 2010. The settlement of tax withholdings on long-term incentive plan awards was $3.4 million and $7.4 million during the first quarter of 2010 and 2011, respectively.

The quarterly distribution amount related to our second quarter 2011 financial results (to be paid in third quarter 2011) is $0.785 per unit. If we are able to meet management's targeted distribution growth of 7% for 2011 and the number of outstanding limited partner units remains at 112.7 million, total cash distributions of approximately $351.0 million will be paid to our unitholders in 2011.

Capital Requirements

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

- maintenance capital expenditures, such as those required to maintain equipment reliability and safety and to

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address environmental regulations; and

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

For the six months ended June 30, 2011, our maintenance capital spending was $19.4 million. For 2011, we expect to incur maintenance capital expenditures for our existing businesses of approximately $65.0 million.

In addition to maintenance capital expenditures, we also incur expansion capital expenditures at our existing facilities. During the first six months of 2011, we spent $75.9 million for organic growth capital, $40.5 million to acquire the remaining interest in MCO, and $17.8 million, collectively, to acquire the remaining undivided interest in our Southlake, Texas terminal, an approximate 38-mile petroleum products pipeline segment connected to our petroleum pipeline system at Reagan, Texas and petroleum products storage tanks in Riverside, Missouri. Based on the progress of expansion projects already underway, we expect to spend approximately $240.0 million for expansion capital during 2011, including acquisitions, with an additional $60.0 million in future years to complete these projects.

Liquidity

Consolidated debt at December 31, 2010 and June 30, 2011 was as follows (in thousands):

	December 31, 2010	June 30, 2011	Weighted-Average Interest Rate at June 30, 2011 (1)
Revolving credit facility	$15,000	$150,000	0.7%
$250.0 million of 6.45% Notes due 2014	249,786	249,814	6.3%
$250.0 million of 5.65% Notes due 2016	252,466	252,252	5.7%
$250.0 million of 6.40% Notes due 2018	259,125	262,034	5.1%
$550.0 million of 6.55% Notes due 2019	581,890	580,216	5.9%
$300.0 million of 4.25% Notes due 2021	298,932	298,974	4.3%
$250.0 million of 6.40% Notes due 2037	248,949	248,956	6.3%
Total debt	$1,906,148	$2,042,246	

(1) Weighted-average interest rate includes the impact of current interest rate swaps, the amortization/accretion of discounts and premiums and the amortization/accretion of gains and losses realized on historical cash flow and fair value hedges.

The face value of our debt at June 30, 2011 was $2.0 billion. The difference between the face value and carrying value of the debt outstanding is the unamortized portion of various fair value hedges and the unamortized discounts and premiums on debt issuances. Note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives o the associated note.

The amounts outstanding under the notes and revolving credit facility described in the table above are senior indebtedness.

Revolving Credit Facility. The total borrowing capacity under the revolving credit facility, which matures in September 2012, was $550.0 million at June 30, 2011. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.3% to 0.8% based on our credit ratings and amounts outstanding under the facility. Additionally, a commitment fee is assessed at a rate from 0.05% to 0.125%, depending on our credit ratings. Borrowings under this facility are used for general purposes, including capital expenditures. As of June 30, 2011, there was $150.0 million outstanding under this facility and $4.6 million obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets but do decrease our borrowing capacity under the facility.

Interest Rate Derivatives

In 2011, we entered into $100.0 million of interest rate swap agreements to hedge against changes in the fair value of a portion of our 6.40% notes due 2018. We account for these agreements as fair value hedges. These agreements effectively convert $100.0 million of our 6.40% fixed-rate notes to floating-rate debt. Under the terms of the agreements, we receive the 6.40% fixed rate of the notes and pay a weighted average rate of six-month LIBOR in arrears plus 2.75%. The agreements

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terminate in July 2018, which is the maturity date of the related notes. Payments settle in January and July each year. During each period, we record the impact of these swaps based on the forward LIBOR curve. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to our interest expense. These interest rate derivatives contain credit-risk-related contingent features, which provide that, in the event we default on any material obligation or in case of a merger in which our credit rating becomes "materially weaker," which would generally be interpreted as falling below investment grade, the counterparties to our interest rate derivative agreements could terminate their respective agreements and require immediate settlement. These interest rate swap agreements were in a net asset position as of June 30, 2011.

Off-Balance Sheet Arrangements

None.

Environmental

Our operations are subject to federal, state and local environmental laws and regulations. We have accrued liabilities for estimated costs at our facilities and properties. We record liabilities when environmental costs are 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.

Clean Air Act - Section 185 Contingent Liability.

Section 185 of the Clean Air Act ("CAA 185") requires states to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas if the designated area within the state did not meet its attainment deadline. Imposition of the fee is mandated for each calendar year after the attainment date until the area is redesignated as an attainment area for ozone. The Environmental Protection Agency ("EPA") is required to collect the fees if a state does not meet the requirements of or if a state is not administering and enforcing CAA 185. The Houston-Galveston region was initially determined to be a severe nonattainment area that did not meet its 2007 attainment deadline and, as such, would be subject to CAA 185. The Texas Commission on Environmental Quality (“TCEQ”) drafted a “Failure to Attain Rule” (the “Rule”) to implement the requirements of CAA 185. The Rule was scheduled to be final in the spring of 2010 and would have provided for the collection of an annual failure to attain fee for emissions from calendar year 2008 forward. We have certain facilities in the Houston area that would have been subject to the TCEQ's Rule.

Under the Rule, the annual fees to be paid by entities within the Houston-Galveston non-attainment area would have been determined by the emissions from a facility that exceed the established baseline. In January 2010, the EPA issued guidance for states developing fee programs under CAA 185. In response to and based on the standards in the EPA's guidance, the TCEQ suspended the draft Rule and submitted a request for a determination by the EPA (a "Termination Determination") that the Houston-Galveston Region no longer qualified as a severe non-attainment area. If TCEQ's request for a Termination Determination were approved by the EPA, the requirement to assess a CAA 185 fee would be terminated. Subsequent to the TCEQ's request for a Termination Determination, the Natural Resource Defense Counsel submitted a petition in federal court challenging the legality of the EPA's guidance. Based upon the EPA's belief and assertion that the guidance would be sustained in federal court, management determined the probability of the assessment of an annual fee for the Houston-Galveston area was remote.

On July 1, 2011, the court issued an opinion in the National Resource Defense Counsel case vacating the EPA's January 2010 guidance memorandum on state's CAA 185 equivalent programs. As a result of the court's ruling, the EPA has instructed the TCEQ that it is unable to approve the Termination Determination request. In addition, the Sierra Club filed a Clean Air Act citizen suit in 2010, Sierra Club v. Jackson, seeking to compel the EPA to collect CAA 185 fees in the Houston-Galveston area.

Based on the recent court decisions and statements by the EPA, management now believes that it is probable that the TCEQ will move forward with its CAA 185 rule making process. A number of potential alternative outcomes exist, including the possibility that we will not be assessed any CAA 185 fees at all. However, management now believes it is probable we will be assessed fees for excess emissions at our Houston area facilities for the years following 2007 and estimates that the range of fees that could be assessed to us to be between $6.4 million and $13.7 million. We have recorded an accrual of $6.4 million related to this matter, of which $4.8 million was recorded as a current environmental liability and $1.6 million was recorded as a long-term environmental liability.

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Other Items

Derivative Agreements. We use NYMEX contracts and butane price swap purchase agreements to help manage commodity price risk. We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell in future periods. Some of these NYMEX contracts qualify for hedge accounting treatment and we designate and account for these contracts as either cash flow or fair value hedges. We use and account for those NYMEX contracts that do not qualify for hedge accounting treatment as economic hedges. We use the butane price swap purchase agreements to hedge against changes in the price of butane we expect to purchase in the future. We elected to not designate the butane price swap purchase agreements as hedges for accounting purposes because the related NYMEX contracts associated with the gasoline sales that will be produced and sold from these future butane purchases did not qualify for hedge accounting treatment. Currently, we have three specific groups of commodities that are being hedged:

- Future sales and purchases of petroleum products associated with our blending and fractionation activities and product overages associated with our petroleum products pipeline over/short activity:

As of June 30, 2011, we had open NYMEX contracts for 1.2 million barrels of petroleum products associated with our blending and fractionation activities that did not qualify for hedge accounting treatment. We recognize the period change in fair value of these agreements in our consolidated income statement. These contracts mature between July 2011 and April 2012. The cumulative amount of unrealized gains through June 30, 2011 associated with these agreements, which are related to products we expect to sell in the future, was $0.3 million. We recorded this amount as an increase in product sales revenues on our consolidated statements of income and as energy commodity derivatives contracts on our consolidated balance sheet, all of which was recognized in 2011. Additionally, we recognized losses of $17.9 million on NYMEX contracts that settled during 2011 related to physical product sales during the first and second quarters of 2011. Furthermore, we realized losses of $1.2 million on NYMEX contracts that settled during 2011 but were rolled to other hedges that are associated with products we expect to sell in the future, of which $1.1 million was recognized during 2011 and $0.1 million was recognized during 2010.

As of June 30, 2011, we had open NYMEX contracts for 0.7 million barrels of petroleum products associated with our blending and fractionation activities that qualified for hedge accounting treatment and were recorded as cash flow hedges. The period change in fair value of these agreements are not included in product sales revenues in our consolidated statement of income until the petroleum products hedged are physically sold. These contracts mature between September and December 2011. The cumulative amount of unrealized gains through June 30, 2011 associated with these agreements, which are related to products we expect to sell in the future, was $2.2 million. Prior to becoming qualified cash flow hedges, we recognized unrealized losses of $2.4 million on these agreements during 2011, which was recorded as a decrease in product sales revenue on our consolidated statements of income.

As of June 30, 2011, we had open NYMEX contracts covering 0.2 million barrels to hedge against future price changes of product overages related to our petroleum products pipeline over/short activity that did not qualify for hedge accounting treatment. We recognize the period change in fair value of these agreements in our consolidated income statement. These contracts mature in July 2011. The cumulative amount of unrealized losses through June 30, 2011 associated with these agreements, which are related to products we expected to sell in the future, was $1.8 million. We recorded this amount as an increase in operating expenses on our consolidated statement of income and as energy commodity derivatives contracts on our consolidated balance sheet, all of which was recognized in 2011. Additionally, we recognized gains of $3.0 million on NYMEX contracts that settled during 2011 related to physical product sales during the first and second quarters of 2011.

As of June 30, 2011, we had open butane price swap positions to purchase 0.3 million barrels of butane that we did not designate as hedges for accounting purposes. We recognize the period change in fair value of these agreements in our consolidated income statement. These contracts mature between August and November 2011. The cumulative amount of unrealized losses through June 30, 2011 associated with these agreements, which are related to products we expect to purchase in the future, was $0.8 million. We recorded this amount as an increase in product purchases on our consolidated statement of income and as energy commodity derivatives contracts on our consolidated balance sheet, all of which was recognized in 2011.

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- Future commodity sales of linefill and working inventory associated with our Houston-to-El Paso pipeline section:

At June 30, 2011, we had open NYMEX contracts covering 1.0 million barrels to hedge against changes in the price of petroleum products associated with the linefill barrels we expect to sell in future periods. These contracts mature between July and December 2011. Because these NYMEX contracts did not qualify for hedge accounting treatment, we recognize the period change in fair value of these agreements in our consolidated income statement. The cumulative amount of unrealized losses through June 30, 2011 associated with these agreements was $7.9 million, of which $4.3 million of losses were recognized during 2011 and $3.6 million of losses were recognized during 2010. Additionally, we recognized $10.9 million of losses associated with the linefill NYMEX contracts that were settled during 2011, related to physical product sales during first and second quarter 2011, that were recorded as a decrease in product sales revenues on our consolidated income statement. The linefill and working inventory associated with our Houston-to-El Paso pipeline section are classified as inventory in current assets on our consolidated balance sheets.

- Future commodity sales of linefill, tank bottom inventory and product overages associated with our crude pipeline and storage activities:

At June 30, 2011, we had open NYMEX contracts covering less than 0.1 million barrels to hedge against future price changes of linefill in a crude pipeline connected to our Cushing, Oklahoma terminal. These contracts qualified for and were designated as fair value hedges and mature in August 2011. The unrealized losses of $0.1 million from these agreements during the current year were fully offset by an adjustment to other current assets and, therefore, there was no impact on product sales revenues. The linefill for our crude pipeline connected to our Cushing terminal is classified as an other current asset on our consolidated balance sheets. Prior to entering into the fair value hedges above, we had open NYMEX contracts hedging less than 0.1 million barrels of linefill in a crude pipeline connected to our Cushing, Oklahoma terminal that did not qualify for hedge accounting treatment. As a result, we recognized $0.1 million of gains during 2011 associated with these agreements, which were recorded as an increase in product sales revenues on our consolidated income statement.

At June 30, 2011, we had open NYMEX contracts covering 0.7 million barrels to hedge future price changes on tank bottom inventory. These contracts qualified for and were designated as fair value hedges and mature in November 2013. The cumulative unrealized losses of $11.0 million from these agreements as of June 30, 2011 were fully offset by an adjustment to the tank bottom inventory and, therefore, there was no impact on product sales revenues. The tank bottom inventory at our Cushing terminal is separately classified as a long-term asset on our consolidated balance sheets.

At June 30, 2011, we had open NYMEX contracts covering 0.1 million barrels to hedge against future price changes of product overages related to our crude pipeline activity that did not qualify for hedge accounting treatment. We recognize the period change in fair value of these agreements in our consolidated income statement. These contracts mature in July 2011. The cumulative amount of unrealized losses through June 30, 2011 associated with these agreements, which are related to products we expect to sell in the future, was less than $0.1 million. We recorded this amount as an increase in operating expenses on our consolidated statement of income and as energy commodity derivatives contracts on our consolidated balance sheet, all of which was recognized in 2011. Additionally, we recognized gains of $0.3 million on NYMEX contracts that settled during 2011 related to physical product sales during second quarter 2011.

The following table provides a summary of the mark-to-market gains and losses associated with NYMEX contracts and the accounting periods in which the gains and losses were recognized in our consolidated statements of income for the periods ended June 30, 2010 and 2011 (in millions):

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2010	
NYMEX losses recorded during the six months ended June 30, 2010 that were associated with physical product sales during the six months ended June 30, 2010	$(3.6)
NYMEX gains recorded in the six months ended June 30, 2010 that were associated with future physical product sales	18.4
Total NYMEX gains which impacted product sales revenues during the six months ended June 30, 2010	$14.8
2011	
NYMEX losses recorded during the six months ended June 30, 2011 that were associated with physical product sales during the six months ended June 30, 2011	$(28.8)
NYMEX losses recorded during 2011 that were associated with future physical product sales	(7.4)
Total NYMEX losses which impacted product sales revenues during the six months ended June 30, 2011	$(36.2)

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 each year. Approximately 40% of our tariffs are subject to this indexing methodology while the remaining 60% of the tariffs can be adjusted at our discretion based on competitive factors. The FERC-approved methodology used for the last five-year period was the annual change in the producer price index for finished goods (“PPI-FG”) plus 1.3%. In December 2010, FERC approved the indexing methodology to be used for the five-year period beginning in July 2011 equal to the change in PPI-FG plus 2.65%. Certain shippers requested a rehearing of this matter by the FERC, and the FERC issued an order denying the requests for rehearing on May 23, 2011, rejecting all arguments alleged by shippers. In July 2011, a shipper filed a petition for review of this matter with the D.C. Circuit. At this time, management is unable to determine what outcome might result from this petition. Based on PPI-FG for 2010, we increased virtually all of our tariff rates by 7% on July 1, 2011, consistent with the new FERC-approved methodology.

Unrecognized Product Gains. Our petroleum terminals operations generate product overages and shortages that result from metering inaccuracies and product evaporation, expansion, releases and contamination. Most of the contracts we have with our customers state that we bear the risk of loss (or gain) from these conditions. When our petroleum terminals experience net product shortages, we recognize expense for those losses in the periods in which they occur. When our petroleum 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 net unrecognized product overages for our petroleum terminals operations had a market value of approximately $1.8 million as of June 30, 2011. 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.

New Accounting Pronouncements

In June 2011, the FASB issued Accounting Standards Update ("ASU") No. 2011-05, Comprehensive Income, which requires either that the income statement include other comprehensive income or a separate comprehensive income statement be reported immediately after the income statement. The option to report other comprehensive income in the statement of owner's equity has been eliminated. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2011, with early adoption permitted. Our adoption of this ASU in first quarter of 2011 had no impact on our results of operations, 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.

Commodity Price Risk

We use derivatives to help manage commodity price risk. Derivatives that qualify as normal purchases and sales are accounted for using traditional accrual accounting. As of June 30, 2011, we had commitments under forward purchase contracts for product purchases of approximately 0.8 million barrels that are being accounted for as normal purchases totaling approximately $77.1 million, and we had commitments under forward sales contracts for product sales of approximately 1.1 million barrels that are being accounted for as normal sales totaling approximately $138.3 million.

We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell from our business activities where we acquire or produce petroleum products. Some of these NYMEX contracts qualify for hedge accounting treatment and we designate and account for these as either cash flow or fair value hedges. We account for those NYMEX contracts that do not qualify for hedge accounting treatment as economic hedges. We also use butane price swap purchase agreements to hedge against changes in the price of butane that we expect to purchase in future periods. At June 30, 2011, we had open NYMEX contracts representing 3.9 million barrels of petroleum products we expect to sell in the future. Additionally, we had open butane price swap positions on the purchase of 0.3 million barrels of butane.

At June 30, 2011, the fair value of our open NYMEX contracts was a liability of $18.4 million and the value of our butane price swap purchase agreements was a liability of $0.8 million. Combined, the net liability was $19.2 million, of which $8.2 million was recorded as energy commodity derivatives contracts and $11.0 million was recorded as other noncurrent liabilities on our consolidated balance sheet.

At June 30, 2011, open NYMEX contracts representing 2.2 million barrels of petroleum products did not qualify for hedge accounting treatment. A $1.00 per barrel increase in the price of these NYMEX contracts for reformulated gasoline blendstock for oxygen blending (“RBOB”) gasoline or heating oil would result in a $2.2 million decrease in our product sales revenues and a $1.00 per barrel decrease in the price of these NYMEX contracts for RBOB or heating oil would result in a $2.2 million increase in our product sales revenues. A $1.00 per barrel increase in the price of butane would result in a $0.3 million decrease in our product purchases and a $1.00 per barrel decrease in the price of butane would result in a $0.3 million increase in our product purchases. However, the cumulative increases or decreases in product sales revenues and purchases we recognize from our open NYMEX and butane price swap contracts will be substantially offset by higher or lower product sales revenues and purchases when the physical sale or purchase of the product occurs. These contracts may be for the purchase or sale of product in markets different from those in which we are attempting to hedge our exposure, resulting in hedges that do not eliminate all price risks.

Interest Rate Risk

In 2011, we entered into $100.0 million of interest rate swap agreements to hedge against changes in the fair value of a portion of our 6.40% notes due 2018. We account for these agreements as fair value hedges. These agreements effectively convert $100.0 million of our 6.40% fixed-rate notes to floating-rate debt. Under the terms of the agreements, we receive the 6.40% fixed rate of the notes and pay a weighted average rate of six-month LIBOR in arrears plus 2.75%. The agreements terminate in July 2018, which is the maturity date of the related notes. Payments settle in January and July each year. During each period, we record the impact of these swaps based on the forward LIBOR curve. Any differences between actual LIBOR determined on the settlement date and our estimate of LIBOR will result in an adjustment to our interest expense. A 0.125% change in LIBOR would result in an annual adjustment to our interest expense of $0.1 million associated with these hedges.

As of June 30, 2011, we had $150.0 million outstanding on our variable rate revolving credit facility. Considering the amount outstanding on our revolving credit facility as of June 30, 2011, our annual interest expense would change by $0.2 million if LIBOR were to change by 0.125%.

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.

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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. There has been no change in our internal control over financial reporting (as defined in Rule 13a-15(f) of the Securities Exchange Act) during the quarter ended June 30, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. On September 1, 2010, we completed an acquisition of a business from BP Pipelines (North America), Inc. Previously, as permitted by the Securities and Exchange Commission, management had elected to exclude this acquisition from its assessment of the effectiveness of our internal control over financial reporting. However, effective with this report, management has included this acquisition in its assessment of the effectiveness of our internal control over financial reporting.

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," "should" and other simila 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 subject to numerous assumptions, uncertainties and risks that are difficult to predict. Therefore, actual outcomes and results may 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 we have discussed in this report:

- overall demand for refined petroleum products, natural gas liquids, crude oil and ammonia in the United States;
- price fluctuations for petroleum products, crude oil and natural gas liquids and expectations about future prices for these products;
- changes in general economic conditions, interest rates and price levels;
- changes in the financial condition of our customers, vendors, derivatives counterparties or lenders;
- our ability to secure financing in the credit and capital markets in amounts and on terms that will allow us to execute our growth strategy and maintain adequate liquidity;
- development of alternative energy sources, increased use of biofuels such as ethanol and biodiesel, increased conservation or fuel efficiency, regulatory developments or other trends that could affect demand for our services;
- changes in the throughput or interruption in service on petroleum pipelines owned and operated by third parties and connected to our assets;
- changes in demand for storage in our petroleum terminals and along our petroleum pipeline system;
- changes in supply patterns for our storage terminals;
- our ability to manage interest rate and commodity price exposures;
- 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;
- weather patterns materially different than historical trends;
- an increase in the competition our operations encounter;
- the occurrence of natural disasters, terrorism, operational hazards or unforeseen interruptions 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 or more aggressive enforcement or increased assessments under existing forms of taxation;
- our ability to identify expansion projects or to complete identified expansion projects on time and at projected costs;
- our ability to make and integrate acquisitions and successfully complete our business strategy;
- changes in laws and regulations that govern the product quality specifications that could impact our ability to produce gasoline volumes through our blending activities or that could require significant capital outlays for compliance;
- changes in laws and regulations to which we are or could become subject, including tax withholding issues, safety, employment and environmental laws and regulations, including laws and regulations designed to address climate change;
- 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,

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limit our ability to borrow additional funds, place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;

- 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 perform on their contractual obligations to us;
- 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.

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PART II
OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In July 2011, Magellan received an information request from the U.S. Environmental Protection Agency, pursuant to Section 308 of the Clean Water Act, regarding a pipeline release in February 2011 near Texas City, Texas. We have accrued an amount for potential monetary sanctions related to this matter of $0.1 million. We do not believe that the ultimate resolution of this matter will have a material impact on our results of operations, financial position or cash flows.

We are a party to various claims, legal actions and complaints arising in the ordinary course of business. While the results cannot be predicted with certainty, management believes 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.

ITEM 1A. RISK FACTORS

In addition to the information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. “Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2010, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not our only risks. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. RESERVED

ITEM 5. OTHER INFORMATION

None.

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ITEM 6. EXHIBITS

Exhibit Number		Description
Exhibit 10.1	—	Magellan Midstream Partners' Long-Term Incentive Plan, as amended and restated on July 21, 2011.
Exhibit 10.2	—	Executive Severance Pay Plan dated July 21, 2011.
Exhibit 12	—	Ratio of earnings to fixed charges.
Exhibit 31.1	—	Certification of Michael N. Mears, principal executive officer.
Exhibit 31.2	—	Certification of John D. Chandler, principal financial officer.
Exhibit 32.1	—	Section 1350 Certification of Michael N. Mears, Chief Executive Officer.
Exhibit 32.2	—	Section 1350 Certification of John D. Chandler, Chief Financial Officer.
Exhibit 101.INS	—	XBRL Instance Document.
Exhibit 101.SCH	—	XBRL Taxonomy Extension Schema.
Exhibit 101.CAL	—	XBRL Taxonomy Extension Calculation Linkbase.
Exhibit 101.DEF	—	XBRL Taxonomy Extension Definition Linkbase.
Exhibit 101.LAB	—	XBRL Taxonomy Extension Label Linkbase.
Exhibit 101.PRE	—	XBRL Taxonomy Extension Presentation Linkbase.

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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 4, 2011.

MAGELLAN MIDSTREAM PARTNERS, L.P.

By: Magellan GP, LLC,
its General Partner

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

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