MAGELLAN MIDSTREAM PARTNERS LP
Form 10-Q
November 01, 2012

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 September 30, 2012

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 12b-2 of the Exchange Act). Yes £ No x

As of October 31, 2012, there were 226,200,872 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 September 30,		Nine Months Ended September 30,	
	2011	2012	2011	2012
Transportation and terminals revenues	$232,064	$255,492	$660,664	$721,807
Product sales revenues	203,253	70,178	600,492	546,476
Affiliate management fee revenue	193	199	578	596
Total revenues	435,510	325,869	1,261,734	1,268,879
Costs and expenses:				
Operating	89,458	103,272	233,142	254,050
Product purchases	159,550	85,819	489,616	478,929
Depreciation and amortization	30,234	31,692	90,261	94,688
General and administrative	20,470	27,551	70,341	76,709
Total costs and expenses	299,712	248,334	883,360	904,376
Equity earnings	1,955	1,749	4,765	4,875
Operating profit	137,753	79,284	383,139	369,378
Interest expense	27,332	29,113	79,806	87,354
Interest income	(11)	(16)	(22)	(80)
Interest capitalized	(665)	(1,439)	(2,526)	(3,331)
Debt placement fee amortization expense	410	519	1,180	1,556
Income before provision for income taxes	110,687	51,107	304,701	283,879
Provision for income taxes	447	585	1,397	2,012
Net income	$110,240	$50,522	$303,304	$281,867
Allocation of net income (loss):				
Limited partners' interest	$110,240	$50,522	$303,367	$281,867
Non-controlling owners’ interest	—	—	(63)	—
Net income	$110,240	$50,522	$303,304	$281,867
Basic and diluted net income per limited partner unit	$0.49	$0.22	$1.34	$1.25
Weighted average number of limited partner units outstanding used for basic and diluted net income per unit calculation	225,728	226,431	225,649	226,348

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 September 30,		Nine Months Ended September 30,	
	2011	2012	2011	2012
Net income	$110,240	$50,522	$303,304	$281,867
Other comprehensive income:				
Net gain on interest rate cash flow hedges	—	10,126	—	11,134
Net gain (loss) on commodity cash flow hedges	6,539	(460)	11,152	1,207
Reclassification of net gain on interest rate cash flow hedges to interest expense	(41)	(41)	(123)	(123)
Reclassification of net gain on commodity hedges to product sales revenues	(1,493)	(1,384)	(1,493)	(1,384)
Amortization of prior service credit and actuarial loss	701	1,269	856	2,974
Curtailment of postretirement benefit plan	—	(4,081)	—	(4,081)
Adjustment to recognize the funded status of postretirement plans	(10,254)	8,325	(10,254)	8,325
Total other comprehensive income (loss)	(4,548)	13,754	138	18,052
Comprehensive income	105,692	64,276	303,442	299,919
Comprehensive loss attributable to non-controlling owners' interest in consolidated subsidiaries	—	—	(63)	—
Comprehensive income attributable to partners' capital	$105,692	$64,276	$303,505	$299,919

See notes to consolidated financial statements.

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

	December 31, 2011	September 30, 2012 (Unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 209,620	$ 100,491
Trade accounts receivable (less allowance for doubtful accounts of $68 and $5 at December 31, 2011 and September 30, 2012, respectively)	82,497	106,208
Other accounts receivable	10,079	8,929
Inventory	258,860	220,716
Energy commodity derivatives contracts, net	4,914	—
Energy commodity derivatives deposits, net	26,917	37,725
Reimbursable costs	5,891	7,294
Other current assets	13,412	19,107
Total current assets	612,190	500,470
Property, plant and equipment	4,080,484	4,287,815
Less: accumulated depreciation	830,762	910,852
Net property, plant and equipment	3,249,722	3,376,963
Equity investments	35,594	73,261
Long-term receivables	2,534	3,190
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of $14,813 and $16,334 at December 31, 2011 and September 30, 2012, respectively)	15,176	13,655
Debt placement costs (less accumulated amortization of $5,799 and $7,355 at December 31, 2011 and September 30, 2012, respectively)	14,615	13,059
Tank bottom inventory	59,473	58,479
Other noncurrent assets	2,437	13,020
Total assets	$ 4,045,001	$ 4,105,357
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 66,384	$ 98,141
Accrued payroll and benefits	30,184	29,905
Accrued interest payable	40,547	33,264
Accrued taxes other than income	27,570	31,933
Environmental liabilities	17,852	16,365
Deferred revenue	39,983	45,065
Accrued product purchases	59,800	70,526
Energy commodity derivatives contracts, net	—	12,575
Other current liabilities	28,735	31,516
Total current liabilities	311,055	369,290
Long-term debt	2,151,775	2,146,749
Long-term pension and benefits	67,080	61,083
Other noncurrent liabilities	19,905	21,411
Environmental liabilities	31,783	35,247
Commitments and contingencies		

Partners’ capital:		
Limited partner unitholders (225,473 units and 226,201 units outstanding at December 31, 2011 and September 30, 2012, respectively)	1,510,604	1,500,726
Accumulated other comprehensive loss	(47,201)	(29,149)
Total partners’ capital	1,463,403	1,471,577
Total liabilities and partners' capital	$ 4,045,001	$ 4,105,357

See notes to consolidated financial statements.

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

	Nine Months Ended September 30, 2011	2012
Operating Activities:		
Net income	$303,304	$281,867
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	90,261	94,688
Debt placement fee amortization	1,180	1,556
Loss on sale, retirement and impairment of assets	7,529	10,575
Equity earnings	(4,765)	(4,875)
Distributions from equity investments	4,365	4,875
Equity-based incentive compensation expense	11,751	12,555
Amortization of prior service credit and actuarial loss	856	2,974
Gain on curtailment of postretirement benefit plan	—	(4,081)
Changes in operating assets and liabilities:		
Restricted cash	14,379	—
Trade accounts receivable and other accounts receivable	2,117	(22,561)
Inventory	(40,712)	38,144
Energy commodity derivatives contracts, net of derivatives deposits	(14,926)	7,047
Reimbursable costs	5,987	(1,403)
Accounts payable	27,293	(14,840)
Accrued payroll and benefits	(8,350)	(279)
Accrued interest payable	(3,228)	(7,283)
Accrued taxes other than income	1,088	4,363
Accrued product purchases	10,846	10,726
Current and noncurrent environmental liabilities	10,668	1,977
Other current and noncurrent assets and liabilities	6,499	(3,783)
Net cash provided by operating activities	426,142	412,242
Investing Activities:		
Property, plant and equipment:		
Additions to property, plant and equipment	(143,163)	(230,015)
Proceeds from sale and disposition of assets	4,555	255
Increase (decrease) in accounts payable related to capital expenditures	(2,544)	45,197
Acquisition of assets	(17,798)	—
Acquisition of non-controlling owners' interests	(40,500)	—
Equity investments	(5,500)	(37,495)
Distributions in excess of equity investment earnings	—	1,228
Other	(1,100)	—
Net cash used by investing activities	(206,050)	(220,830)
Financing Activities:		
Distributions paid	(260,703)	(293,778)
Net borrowings under revolver	(15,000)	—
Borrowings under long-term notes, net of discounts and premiums	260,914	—
Debt placement costs	(2,192)	—

Net receipt from financial derivatives	5,926	—
Increase (decrease) in outstanding checks	(11,045)	6,238
Settlement of tax withholdings on long-term incentive compensation	(7,410)	(13,001)
Net cash used by financing activities	(29,510)	(300,541)
Change in cash and cash equivalents	190,582	(109,129)
Cash and cash equivalents at beginning of period	7,483	209,620
Cash and cash equivalents at end of period	$198,065	$100,491
Supplemental non-cash financing activity:		
Issuance of limited partner units in settlement of equity-based incentive plan awards	$4,315	$7,295

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, 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 August 2012, our general partner's board of directors approved a two-for-one split of our limited partner units, which was completed on October 12, 2012. We have retrospectively restated all limited partner unit and per unit amounts in this report, including earnings per limited partner unit, the weighted average number of limited partner units outstanding for basic and diluted net income per limited partner unit, limited partner units outstanding and per unit cash distribution amounts, for each respective period presented.

In the opinion of management, our accompanying consolidated financial statements, which are unaudited except for the consolidated balance sheet as of December 31, 2011, which is derived from our audited financial statements, include all normal and recurring adjustments necessary to present fairly our financial position as of September 30, 2012, the results of operations for the three and nine months ended September 30, 2011 and 2012 and cash flows for the nine months ended September 30, 2011 and 2012. The results of operations for the nine months ended September 30, 2012 are not necessarily indicative of the results to be expected for the full year ending December 31, 2012.

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, 2011.

2. 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 mark-to-market adjustments from New York Mercantile Exchange ("NYMEX") contracts. We use NYMEX contracts to hedge against changes in the prices of petroleum products we expect to sell from our business activities in which 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 contracts designated as cash flow hedges 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. Changes in the fair value and any ineffectiveness of contracts designated as fair value hedges do not impact product sales. We account for 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 7 - Derivative Financial Instruments for further disclosures regarding our NYMEX contracts.

For the three and nine months ended September 30, 2011 and 2012, product sales revenues included the following (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2012	2011	2012
Physical sale of petroleum products	$173,181	$113,500	$606,603	$584,624
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]	21,865	(36,172)	807	(33,211)
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]	8,281	(7,080)	(6,918)	(5,159)
Other	(74)	(70)	—	222
Total NYMEX contract adjustments	30,072	(43,322)	(6,111)	(38,148)
Total product sales revenues	$203,253	$70,178	$600,492	$546,476

(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 inventory in current assets on our consolidated balance sheets.

3. 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 below. Operating profit includes depreciation and amortization expense and general and administrative ("G&A") expenses that management does not focus on when evaluating the core profitability of our separate operating segments.

	Three Months Ended September 30, 2011 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$167,500	$60,621	$4,644	$(701)	$232,064
Product sales revenues	197,932	5,887	—	(566)	203,253
Affiliate management fee revenue	193	—	—	—	193
Total revenues	365,625	66,508	4,644	(1,267)	435,510
Operating expenses	61,075	22,780	6,349	(746)	89,458
Product purchases	157,356	3,461	—	(1,267)	159,550
Equity earnings	(1,954)	(1)	—	—	(1,955)
Operating margin (loss)	149,148	40,268	(1,705)	746	188,457
Depreciation and amortization expense	18,945	10,179	364	746	30,234
G&A expenses	15,162	4,743	565	—	20,470
Operating profit (loss)	$115,041	$25,346	$(2,634)	$—	$137,753

	Three Months Ended September 30, 2012 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$185,575	$62,961	$7,662	$(706)	$255,492
Product sales revenues	63,065	7,114	—	(1)	70,178
Affiliate management fee revenue	199	—	—	—	199
Total revenues	248,839	70,075	7,662	(707)	325,869
Operating expenses	70,526	29,777	3,667	(698)	103,272
Product purchases	82,335	4,191	—	(707)	85,819
Equity earnings	(1,756)	7	—	—	(1,749)
Operating margin	97,734	36,100	3,995	698	138,527
Depreciation and amortization expense	19,664	10,945	385	698	31,692
G&A expenses	20,057	6,762	732	—	27,551
Operating profit	$58,013	$18,393	$2,878	$—	$79,284

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

	Nine Months Ended September 30, 2011 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$472,730	$172,811	$17,431	$(2,308)	$660,664
Product sales revenues	577,811	23,445	—	(764)	600,492
Affiliate management fee revenue	578	—	—	—	578
Total revenues	1,051,119	196,256	17,431	(3,072)	1,261,734
Operating expenses	150,522	71,403	13,406	(2,189)	233,142
Product purchases	483,369	9,319	—	(3,072)	489,616
Equity earnings	(4,764)	(1)	—	—	(4,765)
Operating margin	421,992	115,535	4,025	2,189	543,741
Depreciation and amortization expense	56,788	30,193	1,091	2,189	90,261
G&A expenses	52,400	16,052	1,889	—	70,341
Operating profit	$312,804	$69,290	$1,045	$—	$383,139

	Nine Months Ended September 30, 2012 (in thousands)				
	Petroleum Pipeline System	Petroleum Terminals	Ammonia Pipeline System	Intersegment Eliminations	Total
Transportation and terminals revenues	$513,062	$190,194	$20,670	$(2,119)	$721,807
Product sales revenues	522,362	24,578	—	(464)	546,476
Affiliate management fee revenue	596	—	—	—	596
Total revenues	1,036,020	214,772	20,670	(2,583)	1,268,879
Operating expenses	173,457	74,399	8,296	(2,102)	254,050
Product purchases	468,026	13,486	—	(2,583)	478,929
Equity earnings	(4,919)	44	—	—	(4,875)
Operating margin	399,456	126,843	12,374	2,102	540,775
Depreciation and amortization expense	59,202	32,190	1,194	2,102	94,688
G&A expenses	56,051	18,617	2,041	—	76,709
Operating profit	$284,203	$76,036	$9,139	$—	$369,378

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

4. Inventory
Inventory at December 31, 2011 and September 30, 2012 was as follows (in thousands):

	December 31, 2011	September 30, 2012
Refined petroleum products	$127,999	$83,127
Natural gas liquids	55,490	65,875
Transmix	60,251	50,759
Crude oil	8,065	14,140
Additives	7,055	6,815
Total inventory	$258,860	$220,716

In conjunction with the reversal and conversion to crude oil service of our Crane-to-Houston pipeline, we discontinued our pipeline linefill activities. Since December 31, 2011, we have sold approximately 0.4 million barrels of the linefill inventory, accordingly. At September 30, 2012, we owned 0.3 million barrels of refined petroleum products linefill inventory with a carrying value of approximately $39.6 million.

5. 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 for the three and nine months ended September 30, 2011 and 2012 (in thousands):

	Three Months Ended September 30, 2011		Three Months Ended September 30, 2012	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of net periodic benefit costs:				
Service cost	$3,251	$141	$2,786	$22
Interest cost	1,358	230	1,240	101
Expected return on plan assets	(1,225)	—	(1,448)	—
Amortization of prior service cost (credit)	76	(212)	77	—
Amortization of actuarial loss	766	1	1,051	141
Settlement cost	70	—	—	—
Curtailment gain	—	—	—	(4,081)
Net periodic benefit cost (credit)	$4,296	$160	$3,706	$(3,817)

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

	Nine Months Ended September 30, 2011		Nine Months Ended September 30, 2012	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of net periodic benefit costs:				
Service cost	$7,221	$323	$9,166	$297
Interest cost	3,257	749	3,647	616
Expected return on plan assets	(3,268)	—	(3,800)	—
Amortization of prior service cost (credit)	230	(638)	231	(424)
Amortization of actuarial loss	1,068	126	2,704	463
Settlement cost	70	—	—	—
Curtailment gain	—	—	—	(4,081)
Net periodic benefit cost (credit)	$8,578	$560	$11,948	$(3,129)

During the current quarter, we modified our retiree medical plan to exclude retiree medical benefits for participants after age 65. As a result of this modification, we recognized a curtailment gain.
Net periodic benefit costs for the pension plans increased in 2012 primarily due to a decrease in the discount rate at December 31, 2011.
Contributions estimated to be paid into the plans in 2012 are $13.3 million and $0.4 million for the pension and other postretirement benefit plans, respectively.

6. Debt

Consolidated debt at December 31, 2011 and September 30, 2012 was as follows (in thousands):

	December 31, 2011	September 30, 2012	Weighted-Average Interest Rate at September 30, 2012 (a)
Revolving credit facility	$—	$—	—%
$250.0 million of 6.45% Notes due 2014	249,844	249,889	6.3%
$250.0 million of 5.65% Notes due 2016	252,037	251,715	5.6%
$250.0 million of 6.40% Notes due 2018	263,477	261,929	5.3%
$550.0 million of 6.55% Notes due 2019	578,521	575,938	5.7%
$550.0 million of 4.25% Notes due 2021	558,932	558,302	4.0%
$250.0 million of 6.40% Notes due 2037	248,964	248,976	6.4%
Total debt	$2,151,775	$2,146,749	5.3%

(a) Weighted-average interest rate includes the impact of 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 on interest expense (see Note 7—Derivative Financial Instruments for detailed information regarding fair value hedges and interest rate swaps).

The revolving credit facility and notes detailed in the table above are senior indebtedness.

The face value of our debt at December 31, 2011 and September 30, 2012 was $2.1 billion. The difference between the face value and carrying value of the debt outstanding is the unamortized portion of various terminated fair value hedges and the unamortized discounts and premiums on debt issuances. Realized gains and losses on fair value hedges and note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of those notes.

Revolving Credit Facility. The total borrowing capacity under our revolving credit facility, which matures in October 2016, is $800.0 million. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings and amounts outstanding under the facility. Additionally, an unused commitment fee is assessed at a rate from 0.125% to 0.3%, depending on our credit ratings. The unused commitment fee was 0.2% at September 30, 2012. Borrowings under this facility may be used for general purposes, including capital expenditures. As of

September 30, 2012, there were no borrowings outstanding under this facility; however, $5.0 million was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets but decrease our borrowing capacity under the facility.

7. 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 sale contracts, NYMEX contracts and butane swap agreements to help manage price changes, which has the effect of locking in most of the product margin realized from our blending activities that we choose to hedge.

We account for the forward purchase and sale contracts we use in our blending and fractionation activities as normal purchases and sales. Forward contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting. As of September 30, 2012, we had commitments under these forward purchase and sale contracts as follows (in millions):

	Value	Barrels
Forward purchase contracts	$79.6	0.8
Forward sale contracts	$71.1	0.6

We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell in future periods. Our NYMEX contracts fall into one of three categories:

Hedge Type	Hedge Purpose	Accounting Treatment
Qualifies For Hedge Accounting Treatment		
Cash Flow Hedge	To hedge the variability in cash flows related to a forecasted transaction.	The effective portion of changes in the value of the hedge are recorded to accumulated other comprehensive income/loss and reclassified to earnings when the forecasted transaction occurs. Any ineffectiveness is recognized currently in earnings.
Fair Value Hedge	To hedge against changes in the fair value of a recognized asset or liability.	The effective portion of changes in the value of the hedge are recorded as adjustments to the asset or liability being hedged. Any ineffectiveness is recognized currently in earnings.
Does Not Qualify For Hedge Accounting Treatment		
Economic Hedge	To effectively serve as either a fair value or a cash flow hedge; however, the derivative agreement does not qualify for hedge accounting treatment or is not designated as a hedge in accordance with Accounting Standards Codification ("ASC") 815, Derivatives and Hedging.	Changes in the value of these agreements are recognized currently in earnings.

We also use butane swap agreements, which are not designated as hedges for accounting purposes, to hedge against changes in the price of butane we expect to purchase in the future. Changes in the fair value of these agreements are recognized currently in earnings as adjustments to product purchases.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As outlined in the table below, our open NYMEX contracts and butane swap agreements at September 30, 2012 were as follows:

Type of Contract/Accounting Methodology	Product Represented by the Contract and Associated Barrels	Maturity Dates
NYMEX - Cash Flow Hedges	0.1 million barrels of refined petroleum products	October 2012
NYMEX - Fair Value Hedges	0.7 million barrels of crude oil	Between October 2012 and November 2013
NYMEX - Economic Hedges	2.4 million barrels of refined petroleum products and crude oil	Between October 2012 and April 2013
Butane Swap Agreements - Economic Hedges	0.4 million barrels of butane	Between October 2012 and April 2013

At September 30, 2012, we had made margin deposits of $37.7 million for our NYMEX contracts, which were recorded as a current asset under 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 swap agreements against our margin deposits under a master netting arrangement with each of our counterparties; however, we have elected to disclose the combined fair values of our open NYMEX and butane swap agreements separately from the related margin deposits on our consolidated balance sheets. Additionally, we have the right to offset the fair values of our NYMEX agreements and butane swap agreements together for each counterparty, which we have elected to do, and we report the combined net balances on our consolidated balance sheets.

Interest Rate Derivatives

During 2012, we entered into a total of $250.0 million of forward-starting interest rate swap agreements to hedge against the variability of future interest payments on debt that we anticipate issuing between December 1, 2013 and December 1, 2014 to refinance our $250.0 million of 6.45% notes due June 1, 2014. Under the terms of these agreements, we will pay a weighted-average fixed interest rate of 2.6% and receive LIBOR beginning June 1, 2014. The hedges have a 30-year maturity, which matches the expected maturity of the anticipated debt issuance; however, the hedges have a mandatory settlement date of June 1, 2014. We account for these agreements as cash flow hedges.

Impact of Derivatives on Income Statement, Balance Sheet and AOCL

The changes in derivative activity included in accumulated other comprehensive loss ("AOCL") for the three and nine months ended September 30, 2011 and 2012 were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Derivative Gains (Losses) Included in AOCL	2011	2012	2011	2012
Beginning balance	$7,856	$5,754	$3,325	$3,161
Net gain on interest rate cash flow hedges	—	10,126	—	11,134
Net gain (loss) on commodity cash flow hedges	6,539	(460)	11,152	1,207
Reclassification of net gain on interest rate cash flow hedges to interest expense	(41)	(41)	(123)	(123)
Reclassification of net gain on commodity hedges to product sales revenues	(1,493)	(1,384)	(1,493)	(1,384)
Ending balance	$12,861	$13,995	$12,861	$13,995

As of September 30, 2012, the net gain (loss) estimated to be classified to interest expense and product sales revenues over the next twelve months from AOCL is approximately $0.2 million and $(0.2) million, respectively.

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The following table provides a summary of the effect on our consolidated statements of income for the three and nine months ended September 30, 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	Nine Months Ended	Three Months Ended	Nine Months Ended
		September 30, 2011			
Interest rate swap agreements	Interest expense	$264	$1,275	$1,333	$7,556

During 2012, we had open NYMEX contracts on 0.7 million barrels of crude oil that were designated as fair value hedges. Because there was no ineffectiveness recognized on these hedges, the unrealized losses of $5.4 million from the agreements as of September 30, 2012 were fully offset by an increase of $5.5 million to tank bottom inventory and a decrease of $0.1 million to other current assets; therefore, there was no net impact from these agreements on income/expense.

The following tables provide a summary of the effect on our consolidated statements of income for the three and nine months ended September 30, 2011 and 2012 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):

	Three Months Ended September 30, 2011		
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	6,539	Product sales revenues	1,493
Total cash flow hedges	$6,539	Total	$ 1,534

	Three Months Ended September 30, 2012		
Derivative Instrument	Amount of Gain (Loss) 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	$10,126	Interest expense	$ 41
NYMEX commodity contracts	(460)	Product sales revenues	1,384
Total cash flow hedges	$9,666	Total	$ 1,425

	Nine Months Ended September 30, 2011		
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	$ 123
NYMEX commodity contracts	11,152	Product sales revenues	1,493
Total cash flow hedges	$11,152	Total	$ 1,616

	Nine Months Ended September 30, 2012		
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	$11,134	Interest expense	$ 123
NYMEX commodity contracts	1,207	Product sales revenues	1,384
Total cash flow hedges	$12,341	Total	$ 1,507

There was no ineffectiveness recognized on the financial instruments disclosed in the above tables during the three and nine months ended September 30, 2011 or 2012.

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

The following table provides a summary of the effect on our consolidated statements of income for the three and nine months ended September 30, 2011 and 2012 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		Nine Months Ended	
Derivative Instrument	Location of Gain (Loss) Recognized on Derivative	September 30, 2011	September 30, 2012	September 30, 2011	September 30, 2012
NYMEX commodity contracts	Product sales revenues	$28,579	$(44,706)	$(7,604)	$(39,532)
NYMEX commodity contracts	Operating expenses	(923)	(7,733)	598	(3,216)
Butane swap agreements	Product purchases	(50)	3,007	(889)	(1,620)
	Total	$27,606	$(49,432)	$(7,895)	$(44,368)

The following tables provide a summary of the fair value of derivatives accounted for under ASC 815, Derivatives and Hedging, which are presented on a net basis in our consolidated balance sheets, that were designated as hedging instruments as of December 31, 2011 and September 30, 2012 (in thousands):

	December 31, 2011			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts	$31	Energy commodity derivatives contracts	$—
NYMEX commodity contracts	Other noncurrent assets	—	Other noncurrent liabilities	6,457
	Total	$31	Total	$6,457

	September 30, 2012			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts	$69	Energy commodity derivatives contracts	$177
NYMEX commodity contracts	Other noncurrent assets	—	Other noncurrent liabilities	5,463
Forward-starting interest rate swap agreements	Other noncurrent assets	11,134	Other noncurrent liabilities	—
	Total	$11,203	Total	$5,640

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables provide a summary of the fair value of derivatives accounted for under ASC 815, Derivatives and Hedging, which are presented on a net basis in our consolidated balance sheets, that were not designated as hedging instruments as of December 31, 2011 and September 30, 2012 (in thousands):

	December 31, 2011			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts	$6,403	Energy commodity derivatives contracts	$1,514
Butane swap agreements	Energy commodity derivatives contracts	28	Energy commodity derivatives contracts	34
	Total	$6,431	Total	$1,548

	September 30, 2012			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts	$259	Energy commodity derivatives contracts	$11,656
Butane swap agreements	Energy commodity derivatives contracts	648	Energy commodity derivatives contracts	1,718
	Total	$907	Total	$13,374

8. Commitments and Contingencies

Clean Air Act - Section 185 Liability

Section 185 of the Clean Air Act ("CAA 185") requires states under certain conditions to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas 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 administer and enforce 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") is currently considering a “Failure to Attain Rule” to implement the requirements of CAA 185. The draft Failure to Attain Rule is anticipated to be adopted in the spring of 2013 and is expected to provide for the collection of an annual failure to attain fee for excess emissions. We have certain facilities in the Houston area that we expect will be subject to the TCEQ's Failure to Attain Rule. We have recorded an accrual of $8.9 million related to this matter for the period of 2008 through 2010, with a possible range of loss from zero to $13.7 million. This accrual is reflected as a long-term environmental liability at September 30, 2012.

Osage Complaint

In June 2012, HollyFrontier Refining & Marketing LLC (“HollyFrontier”) filed a complaint with the Federal Energy Regulatory Commission ("FERC") alleging that Osage Pipe Line Company, LLC (“Osage”) has been over-earning on its rates for transportation on Osage's crude oil pipeline system from Cushing, Oklahoma to El Dorado, Kansas. We own 50% of Osage and serve as its operator. We believe that it is reasonably possible that Osage could incur a liability as a result of this complaint. As a 50% owner of Osage, we currently estimate that our ultimate exposure in this matter will be within a range of zero to approximately $6.3 million. We believe the claims should be denied and are defending the Osage rates vigorously. As of September 30, 2012, neither we nor Osage had any amounts accrued for this matter.

MF Global Holdings Ltd. Bankruptcy

In October 2011, MF Global Holdings Ltd., the parent of MF Global Inc. ("MF Global"), filed for bankruptcy protection under Chapter 11 of the U.S. bankruptcy laws, and a trustee was appointed to oversee the liquidation of MF Global under the Securities Investor Protection Act ("SIPA"). At that time, MF Global served as our sole clearing agent for NYMEX futures contracts.

The Chicago Mercantile Exchange ("CME") requires us to maintain adequate margin against our NYMEX positions, which our clearing agent is required to hold on our behalf in a segregated account. In October 2011, MF Global disclosed to the CME that it had a "significant shortfall" in its segregated customer accounts. We transferred our existing trading positions at MF Global to a new clearing agent in November 2011, and all of our NYMEX activity is now being conducted with a different clearing agent.

As of the date of transfer of our account, MF Global owed us $29.4 million; however, we have subsequently received $23.6 million as partial payment on our account. We have a claim outstanding with the Trustee for the SIPA liquidation of MF Global for the remaining amount owed to us by MF Global of $5.8 million. At this point it is uncertain what additional funds MF Global will have available for distribution to its former customers as well as how the claims against MF Global's remaining assets may be prioritized. As of September 30, 2012, we have not reserved any of our MF Global receivable balance.

Environmental Liabilities

Liabilities recognized for estimated environmental costs were $49.6 million and $51.6 million at December 31, 2011 and September 30, 2012, 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 expenses were $3.6 million and $10.0 million for the three months ended September 30, 2011 and 2012, respectively, and $16.1 million and $12.7 million for the nine months ended September 30, 2011 and 2012, respectively. The higher environmental expenses in 2011 were primarily due to the CAA 185 liability accrual (described above).

Environmental Receivables

Receivables from insurance carriers and other third parties related to environmental matters at December 31, 2011 were $7.7 million, of which $5.2 million and $2.5 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheet. Receivables from insurance carriers related to environmental matters at September 30, 2012 were $8.3 million, of which $5.1 million and $3.2 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheet.

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 $3.4 million as of September 30, 2012. 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 results of operations, financial position or cash flows.

9. 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 September 30, 2012, permits the grant of awards covering an aggregate of 9.4 million of our limited partner units. The remaining units available under the LTIP at September 30, 2012 total 2.4 million. The compensation committee of our general partner's board of directors administers our LTIP.

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

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

	Three Months Ended September 30, 2011			Nine Months Ended September 30, 2011		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
2009 awards	$600	$657	$1,257	$3,835	$2,862	$6,697
2010 awards	387	189	576	1,724	708	2,432
2011 awards	578	153	731	1,702	442	2,144
Retention awards	170	—	170	478	—	478
Total	$1,735	$999	$2,734	$7,739	$4,012	$11,751
Allocation of LTIP expense on our consolidated statements of income:						
G&A expense			$2,375			$10,696
Operating expense			359			1,055
Total			$2,734			$11,751

	Three Months Ended September 30, 2012			Nine Months Ended September 30, 2012		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
2010 awards	$1,489	$1,776	$3,265	$3,666	$2,954	$6,620
2011 awards	684	566	1,250	2,111	1,021	3,132
2012 awards	581	259	840	1,711	557	2,268
Retention awards	192	—	192	535	—	535
Total	$2,946	$2,601	$5,547	$8,023	$4,532	$12,555
Allocation of LTIP expense on our consolidated statements of income:						
G&A expense			$4,940			$11,160
Operating expense			607			1,395
Total			$5,547			$12,555

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

10. Distributions
Distributions we paid during 2011 and 2012 were as follows (in thousands, except per unit amounts):

Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution to Limited Partners
2/14/2011	$0.37875	$85,398
5/13/2011	0.38500	86,807
8/12/2011	0.39250	88,498
Through 9/30/2011	1.15625	260,703
11/14/2011	0.40000	90,189
Total	$1.55625	$350,892
2/14/2012	$0.40750	$92,177
5/15/2012	0.42000	95,004
8/14/2012	0.47125	106,597
Through 9/30/2012	1.29875	293,778
11/14/2012[a]	0.48500	109,707
Total	$1.78375	$403,485

(a) Our general partner's board of directors declared this cash distribution on October 24, 2012 to be paid on November 14, 2012 to unitholders of record at the close of business on November 6, 2012.

11. 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. 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 change in value of the associated contracts.
- Energy commodity derivatives contracts. These include NYMEX futures and butane swap 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 7 - Derivative Financial Instruments for further disclosures regarding these contracts.
- Forward-starting interest rate swap agreements. Fair value was determined based on an assumed exchange, at the end of each period, in an orderly transaction with a market participant in the market in which the financial instrument is traded, adjusted for the effect of counterparty credit risk. We calculated the exchange value using present value techniques on estimated future cash flows based on forward interest rate curves.
- Long-term receivables. Fair value was determined by estimating the present value of future cash flows using a risk-free rate of interest derived from US treasury rates.
- Debt. The fair value of our publicly traded notes was based on the prices of those notes at December 31, 2011 and September 30, 2012. The carrying amount of borrowings, if any, under our revolving credit facility approximates fair value due to the variable rates of that instrument.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
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The following table reflects the carrying amounts and fair values of our financial instruments as of December 31, 2011 and September 30, 2012 (in thousands):

Assets (Liabilities)	December 31, 2011 Carrying Amount	December 31, 2011 Fair Value	September 30, 2012 Carrying Amount	September 30, 2012 Fair Value
Cash and cash equivalents	$209,620	$209,620	$100,491	$100,491
Energy commodity derivatives deposits (current assets)	$26,917	$26,917	$37,725	$37,725
Energy commodity derivatives contracts (current assets)	$4,914	$4,914	$—	$—
Energy commodity derivatives contracts (current liabilities)	$—	$—	$(12,575)	$(12,575)
Forward-starting interest rate swap agreements (noncurrent assets)	$—	$—	$11,134	$11,134
Energy commodity derivatives contracts (noncurrent liabilities)	$(6,457)	$(6,457)	$(5,463)	$(5,463)
Long-term receivables	$2,534	$2,510	$3,190	$3,168
Debt	$(2,151,775)	$(2,389,700)	$(2,146,749)	$(2,471,685)

Fair Value Measurements

The following tables summarize the recurring fair value measurements of our NYMEX commodity contracts, forward-starting interest rate swap agreements, long-term receivables and debt as of December 31, 2011 and September 30, 2012, based on the three levels established by ASC 820-10-50; Fair Value Measurements and Disclosures—Overall—Disclosure (in thousands):

		Fair Value Measurements as of December 31, 2011 using:		
Assets (Liabilities)	Total	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 assets)	$4,914	$4,914	$—	$—
Energy commodity derivatives contracts (noncurrent liabilities)	$(6,457)	$(6,457)	$—	$—
Long-term receivables	$2,510	$—	$—	$2,510
Debt	$(2,389,700)	$(2,389,700)	$—	$—

		Fair Value Measurements as of September 30, 2012 using:		
Assets (Liabilities)	Total	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 liabilities)	$(12,575)	$(12,575)	$—	$—

Forward-starting interest rate swap agreements (noncurrent assets)	$11,134	$—	$11,134	$—
Energy commodity derivatives contracts (noncurrent liabilities)	$(5,463)	$(5,463)	$—	$—
Long-term receivables	$3,168	$—	$—	$3,168
Debt	$(2,471,685)	$(2,471,685)	$—	$—

12. Related Party Transactions

We own a 50% interest in Osage and receive a management fee for the operation of its crude oil pipeline. We received management fees from this company of $0.2 million for each of the three months ended September 30, 2011 and 2012, and $0.6 million for each of the nine months ended September 30, 2011 and 2012. We reported these fees as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in Texas Frontera, LLC ("Texas Frontera"), which has constructed 0.8 million barrels of refined products storage at our Galena Park, Texas terminal. These tanks, which began operation in October 2012, are leased to an affiliate of Texas Frontera under a long-term lease agreement. Additionally, we have constructed certain infrastructure assets at our Galena Park terminal which allow for the operation of the Texas Frontera tanks. For the nine months ended September 30, 2012, we contributed $3.9 million to Texas Frontera, of which we paid $2.5 million in cash and contributed assets of $1.4 million.

We own a 50% interest in Double Eagle Pipeline LLC ("Double Eagle"), which is in the process of constructing a 140-mile pipeline that will connect to an existing pipeline segment owned by an affiliate of Double Eagle. Once completed, Double Eagle will transport condensate from the Eagle Ford shale formation to our terminal in Corpus Christi, Texas. For the nine months ended September 30, 2012, we contributed $34.5 million for construction funding requests from Double Eagle. We expect these assets to be fully operational in mid-2013.

Barry R. Pearl is an independent member of our general partner's board of directors and is also a director of Targa Resources Partners, L.P. ("Targa"). In the normal course of business, we purchase petroleum products from subsidiaries of Targa. For the three months ended September 30, 2011 and 2012, respectively, we made purchases of petroleum products from subsidiaries of Targa of less than $0.1 million. For the nine months ended September 30, 2011 and 2012, respectively, we made purchases of petroleum products from subsidiaries of Targa of $0.3 million and $12.5 million. These purchases were made on the same terms as comparable third-party transactions.

In January 2011, our former chief executive officer, Don R. Wellendorf, retired. In conjunction with Mr. Wellendorf's retirement, our general partner's board of directors engaged Mr. Wellendorf as a consultant to us for a period of twelve months beginning in February 2011 for consideration of $0.3 million and an agreement that certain of his previously-awarded phantom unit awards would not be forfeited. Expense associated with these awards for the nine months ended September 30, 2011 and 2012 was $1.9 million and $0.4 million, respectively.

13. Subsequent Events

Recognizable events

No recognizable events occurred during the period.

Non-recognizable events

In October 2012, our general partner's board of directors declared a quarterly distribution of $0.485 per unit to be paid on November 14, 2012 to unitholders of record at the close of business on November 6, 2012. The total cash distributions to be paid are $109.7 million.

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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 principally engaged in the transportation, storage and distribution of petroleum products. As of September 30, 2012, our three operating segments included:

- petroleum pipeline system, comprised of approximately 9,600 miles of pipeline and 50 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, 2011.

Recent Developments

Two-For-One Split. In August 2012, our general partner's board of directors approved a two-for-one split of our limited partner units, which was completed on October 12, 2012. We have retrospectively restated all limited partner unit and per unit amounts, including distribution amounts, in this report.

Proposed BridgeTex Pipeline. In June 2012, we and Occidental Petroleum Corporation ("Occidental") launched an open season to jointly assess customer interest in a new common carrier pipeline construction project to transport approximately 300,000 barrels per day of crude oil from Colorado City, Texas to the Houston Gulf Coast area. Subject to necessary permits and regulatory approvals, the proposed BridgeTex Pipeline is expected to begin service during mid-2014. As currently contemplated, we would own 50% of the joint project, and our share of the project cost would be about $600.0 million. We remain in advanced discussions with Occidental but cannot provide assurance that we and Occidental will proceed with this proposed project.

Cash Distribution. In October 2012, the board of directors of our general partner declared a quarterly cash distribution of $0.485 per unit for the period of July 1, 2012 through September 30, 2012. This quarterly cash distribution will be paid on November 14, 2012 to unitholders of record on November 6, 2012. Total distributions to be paid under this declaration are approximately $109.7 million.

Results of Operations

We believe that investors benefit from having access to the same financial measures utilized 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 following tables. Operating profit includes expense items, such as depreciation and amortization expense and general and administrative ("G&A") expenses, which management does not focus on when evaluating the core profitability of our separate operating segments. 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 September 30, 2011 Compared to Three Months Ended September 30, 2012

	Three Months Ended September 30,		Variance Favorable (Unfavorable)	
	2011	2012	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$167.5	$185.6	$18.1	11
Petroleum terminals	60.6	63.0	2.4	4
Ammonia pipeline system	4.6	7.7	3.1	67
Intersegment eliminations	(0.6)	(0.8)	(0.2)	(33)
Total transportation and terminals revenues	232.1	255.5	23.4	10
Affiliate management fee revenue	0.2	0.2	—	—
Operating expenses:				
Petroleum pipeline system	61.1	70.6	(9.5)	(16)
Petroleum terminals	22.8	29.8	(7.0)	(31)
Ammonia pipeline system	6.3	3.7	2.6	41
Intersegment eliminations	(0.7)	(0.8)	0.1	14
Total operating expenses	89.5	103.3	(13.8)	(15)
Product margin:				
Product sales revenues	203.3	70.2	(133.1)	(65)
Product purchases	159.6	85.8	73.8	46
Product margin[(a)]	43.7	(15.6)	(59.3)	n/a
Equity earnings	2.0	1.8	(0.2)	(10)
Operating margin	188.5	138.6	(49.9)	(26)
Depreciation and amortization expense	30.3	31.7	(1.4)	(5)
G&A expense	20.4	27.6	(7.2)	(35)
Operating profit	137.8	79.3	(58.5)	(42)
Interest expense (net of interest income and interest capitalized)	26.7	27.6	(0.9)	(3)
Debt placement fee amortization expense	0.4	0.6	(0.2)	(50)
Income before provision for income taxes	110.7	51.1	(59.6)	(54)
Provision for income taxes	0.5	0.5	—	—
Net income	$110.2	$50.6	$(59.6)	(54)
Operating Statistics:				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.118	$1.088		
Volume shipped (million barrels):[(b)]				
Refined products:				
Gasoline	48.4	61.8		
Distillates	36.5	36.5		
Aviation fuel	7.5	5.9		
Liquefied petroleum gases	1.4	3.2		
Crude oil	12.6	19.3		
Total volume shipped	106.4	126.7		
Petroleum terminals:				
Storage terminal average utilization (million barrels per month)	33.1	34.3		

Inland terminal throughput (million barrels)	29.4	29.7
Ammonia pipeline system:		
Volume shipped (thousand tons)	134	210

(a) Product margin does not include depreciation or amortization expense.
(b) Excludes capacity leases.

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Transportation and terminals revenues increased $23.4 million resulting from:

- an increase in petroleum pipeline system revenues of $18.1 million resulting primarily from:
  - a 19% increase in transportation volumes, mainly due to increases in gasoline and crude oil shipments. Gasoline volumes increased 28% attributable primarily to higher volumes on our South Texas pipeline system as well as higher consumer demand in the markets served by our system. Crude volumes increased 53% resulting from deliveries to additional locations that have been connected to our pipeline system and increased deliveries to existing customers; and
  - a slight decrease in the average tariff rate as the 8.6% rate increase we implemented on July 1, 2012 was offset by more short-haul movements due to higher crude volumes and South Texas gasoline volumes, which ship at a lower rate than our other pipeline shipments;
- an increase in petroleum terminals revenues of $2.4 million primarily due to leasing tanks constructed throughout 2011, including new crude oil storage at Cushing, Oklahoma, and higher rates at our marine terminals; and
- an increase in ammonia pipeline system revenues of $3.1 million primarily because of higher shipments and an increase in average tariff rates charged.

Operating expenses increased $13.8 million resulting from:

- an increase in petroleum pipeline system expenses of $9.5 million primarily due to additional asset integrity work, higher property taxes, more losses on various asset retirements and replacements and increased environmental remediation accruals for historical releases. These items were partially offset by higher product overages (which reduce operating expenses) in the current period;
- an increase in petroleum terminals expenses of $7.0 million primarily due to an increase in environmental liabilities related to a historical acquisition, more asset integrity work and higher personnel costs in the current period; and
- a decrease in ammonia pipeline system expenses of $2.6 million primarily due to lower asset integrity costs in the current period because of hydrostatic testing we conducted last year.

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 swap agreements to hedge against changes in the price of butane 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 $59.3 million primarily due to unrealized losses on NYMEX contracts in the current quarter (compared to unrealized gains in third quarter 2011) due to increasing product prices in the current period. Excluding mark-to-market adjustments on these open NYMEX contracts, we earned slightly more product margin in third quarter 2012 as higher blending profits offset lower results from our fractionation and linefill management activities. See Other Items—Commodity Derivative Agreements—Product Sales below for more information about our NYMEX contracts.

Depreciation and amortization expense increased $1.4 million primarily due to expansion capital projects placed into service since third quarter 2011.

G&A expense increased $7.2 million primarily due to higher personnel costs resulting from an increase in long-term incentive compensation costs for above-target payout estimates and a higher price for our limited partner units, an increase in the bonus accrual because of higher-than-expected financial results in 2012 and increased compensation and benefit costs.

Interest expense, net of interest income and interest capitalized, increased $0.9 million in part due to higher commitment fees on our revolving credit facility due to the increase in borrowing capacity since late 2011. Our average debt outstanding of $2.1 billion was slightly higher than third quarter 2011 and our weighted average rate of 5.3% in third quarter 2012 was essentially unchanged.

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	Nine Months Ended September 30,		Variance Favorable (Unfavorable)	
	2011	2012	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Petroleum pipeline system	$472.7	$513.1	$40.4	9
Petroleum terminals	172.8	190.2	17.4	10
Ammonia pipeline system	17.4	20.7	3.3	19
Intersegment eliminations	(2.2)	(2.2)	—	—
Total transportation and terminals revenues	660.7	721.8	61.1	9
Affiliate management fee revenue	0.6	0.6	—	—
Operating expenses:				
Petroleum pipeline system	150.5	173.5	(23.0)	(15)
Petroleum terminals	71.4	74.4	(3.0)	(4)
Ammonia pipeline system	13.4	8.3	5.1	38
Intersegment eliminations	(2.1)	(2.1)	—	—
Total operating expenses	233.2	254.1	(20.9)	(9)
Product margin:				
Product sales revenues	600.5	546.5	(54.0)	(9)
Product purchases	489.6	478.9	10.7	2
Product margin[(a)]	110.9	67.6	(43.3)	(39)
Equity earnings	4.8	4.9	0.1	2
Operating margin	543.8	540.8	(3.0)	(1)
Depreciation and amortization expense	90.3	94.7	(4.4)	(5)
G&A expense	70.3	76.7	(6.4)	(9)
Operating profit	383.2	369.4	(13.8)	(4)
Interest expense (net of interest income and interest capitalized)	77.3	83.9	(6.6)	(9)
Debt placement fee amortization expense	1.2	1.6	(0.4)	(33)
Income before provision for income taxes	304.7	283.9	(20.8)	(7)
Provision for income taxes	1.4	2.0	(0.6)	(43)
Net income	$303.3	$281.9	$(21.4)	(7)
Operating Statistics:				
Petroleum pipeline system:				
Transportation revenue per barrel shipped	$1.088	$1.091		
Volume shipped (million barrels):[(b)]				
Refined products:				
Gasoline	153.1	163.8		
Distillates	99.0	99.9		
Aviation fuel	20.3	16.7		
Liquefied petroleum gases	4.5	7.9		
Crude oil	29.8	51.4		
Total volume shipped	306.7	339.7		
Petroleum terminals:				
Storage terminal average utilization (million barrels per month)	31.4	34.6		
Inland terminal throughput (million barrels)	86.3	87.7		
Ammonia pipeline system:				
Volume shipped (thousand tons)	546	592		

(a) Product margin does not include depreciation or amortization expense.
(b) Excludes capacity leases.

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Transportation and terminals revenues increased $61.1 million primarily resulting from:

- an increase in petroleum pipeline system revenues of $40.4 million primarily resulting from:
  - an 11% increase in transportation volumes primarily due to higher gasoline and crude oil shipments. Gasoline volumes increased 7% attributable to higher volumes on our South Texas pipeline system as well as higher consumer demand in the markets served by our system. Crude volumes increased 73% resulting from deliveries to additional locations that have been connected to our pipeline system and increased deliveries to existing customers;
  - essentially unchanged average tariffs as the mid-year tariff increases we implemented were mostly offset by more short-haul movements, in part due to significantly higher crude volumes and gasoline volumes on our South Texas pipeline segment, which ship at a lower rate than our other pipeline shipments; and
  - increased demand for leased storage along our pipeline system;
- an increase in petroleum terminals revenues of $17.4 million primarily due to tanks constructed throughout 2011, including new crude oil storage at Cushing, Oklahoma and refined products storage in the Gulf Coast area, and higher rates at our marine terminals; and
- an increase in ammonia pipeline system revenues of $3.3 million because of higher shipments and an increase in average tariff rates charged.

Operating expenses increased $20.9 million, resulting from:

- an increase in petroleum pipeline system expenses of $23.0 million primarily due to additional asset integrity work, lower product overages (which reduce operating expenses), an increase in property taxes, higher losses on various asset retirements and replacements and higher personnel costs, which were partially offset by impairment charges in 2011 for a system terminal we closed and a potential air emission fee accrual in 2011;
- an increase in petroleum terminals expenses of $3.0 million primarily due to an increase in environmental liabilities related to a historical acquisition and higher asset integrity expenses and personnel costs in the current year, partially offset by an accrual recognized in 2011 for potential air emission fees with no corresponding charge in the current period and insurance reimbursements received in 2012 for a hurricane-related claim; and
- a decrease in ammonia pipeline system expenses of $5.1 million primarily due to lower asset integrity costs because of hydrostatic testing conducted in 2011 and lower environmental accruals in the current year.

Product margin decreased $43.3 million primarily due to unrealized losses on NYMEX contracts in the current year (compared to unrealized gains in 2011) due to increasing product prices in the current period. Excluding mark-to-market adjustments on our open NYMEX contracts, we earned higher product margin due to selling more product from our blending activities at higher prices. See Other Items—Commodity Derivative Agreements—Product Sales below for more information about our NYMEX contracts.

Depreciation and amortization expense increased $4.4 million primarily due to expansion capital projects placed into service over the past year.

G&A expense increased $6.4 million primarily due to higher personnel costs resulting from an increase in long-term incentive compensation costs for above-target payout estimates and a higher price for our limited partner units, an increase in the bonus accrual because of higher financial results in 2012 and increased compensation and benefit costs.

Interest expense, net of interest income and interest capitalized, increased $6.6 million. Our average debt outstanding increased to $2.1 billion for 2012 from $2.0 billion for 2011 primarily due to borrowings for expansion capital expenditures, including $250.0 million of 4.25% senior notes issued in August 2011. The weighted-average interest rate on our borrowings, after giving effect to the impact of associated fair value hedges, decreased to 5.3% in 2012 from 5.4% in 2011. Further, we paid higher commitment fees on our revolving credit facility due to the increase in borrowing capacity since late 2011.

Distributable Cash Flow

Distributable cash flow and adjusted EBITDA are non-GAAP measures that management uses to evaluate our ability to generate cash for distribution to our limited partners. Management also uses this distributable cash flow measure as a basis for recommending to our general partner's 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 and adjusted EBITDA for the nine months ended September 30, 2011 and 2012 to net

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income, which is its nearest comparable GAAP financial measure, was as follows (in millions):

	Nine Months Ended September 30,		Increase
	2011	2012	(Decrease)
Net income	$303.3	$281.9	$(21.4)
Interest expense, net	77.3	83.9	6.6
Depreciation and amortization(1)	91.4	96.2	4.8
Equity-based incentive compensation expense(2)	4.3	(0.4)	(4.7)
Asset retirements and impairments	7.5	10.6	3.1
Commodity-related adjustments:			
Derivative (gains) losses recognized in the period associated with future product transactions(3)	(25.3)	18.4	43.7
Derivative losses recognized in previous periods associated with products sold in the period(4)	(15.7)	(6.7)	9.0
Lower-of-cost-or-market adjustments	3.0	(1.0)	(4.0)
Houston-to-El Paso cost of sales adjustments(5)	0.4	8.2	7.8
Total commodity-related adjustments	(37.6)	18.9	56.5
Other	(1.4)	0.4	1.8
Adjusted EBITDA	444.8	491.5	46.7
Interest expense, net	(77.3)	(83.9)	(6.6)
Maintenance capital	(38.3)	(47.2)	(8.9)
Distributable cash flow	$329.2	$360.4	$31.2

(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 nine months ended September 30, 2011 and 2012 was $11.7 million and $12.6 million, respectively. However, the figures above include an adjustment for minimum statutory tax withholdings we paid in 2011 and 2012 of $7.4 million and $13.0 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 that have not been designated as hedges for accounting purposes. These amounts represent the gains or losses from these economic hedges recognized in our earnings for products that had not physically sold as of the period end date.

(4) These amounts represent, for products physically sold in the reporting period, the gains or losses from the associated commodity derivative agreements recognized in our earnings during periods prior to these reporting periods.

(5) Cost of goods sold adjustment related to 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 net income.

Distributable cash flow increased by $31.2 million. The change in net income and depreciation and amortization is discussed in detail in Results of Operations above, the change in equity-based compensation is discussed in footnote 2 to the table above and a discussion of our maintenance capital expenditures is provided in Capital Requirements below. The change in distributable cash flow from commodity-related adjustments is primarily due to the impact of product price changes during each period on economic hedges that do not qualify for hedge accounting treatment.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $426.1 million and $412.2 million for the nine months ended September 30, 2011 and 2012, respectively. The $13.9 million decrease from 2011 to 2012 was primarily attributable to:

- a $21.4 million decrease in net income;
- a $42.1 million decrease resulting from a $14.8 million decrease in accounts payable in 2012 versus a $27.3 million increase in accounts payable in 2011 primarily due to the timing of invoices paid to vendors and suppliers;
- a $24.7 million decrease resulting from a $22.6 million increase in trade accounts receivable and other accounts

receivable in 2012 versus a $2.1 million decrease during 2011 primarily due to timing of payments from our customers;

- a $14.4 million decrease due to a change in restricted cash. During first quarter 2011, we acquired the non-controlling owner's interest in one of our subsidiaries, which removed our restriction to that entity's cash. As a result of that transaction, cash from operations increased $14.4 million in 2011; and
- a $8.7 million decrease resulting from a $2.0 million increase in current and noncurrent environmental liabilities in 2012 versus a $10.7 million increase in current and noncurrent environmental liabilities in 2011 primarily due to a contingent liability accrual in 2011 related to Section 185 of the Clean Air Act (see Environmental below for further details regarding this matter).

These decreases were partially offset by:

- a $78.8 million increase primarily resulting from higher prices and volumes of inventory purchases in 2011 as compared to 2012; specifically, a $38.1 million decrease in inventory in 2012, primarily due to the reduction of our Houston-to-El Paso pipeline section linefill working inventory, versus a $40.7 million increase in inventory in 2011; and
- a $21.9 million increase resulting from a $7.0 million increase in energy commodity derivatives contracts, net of derivatives deposits in 2012, versus a $14.9 million decrease for derivative contracts in 2011 primarily due to lower product prices and a decrease in the number of NYMEX commodity contracts during 2012.

Net cash used by investing activities for the nine months ended September 30, 2011 and 2012 was $206.1 million and $220.8 million, respectively. During 2012, we spent $230.0 million for capital expenditures, which included $47.2 million for maintenance capital and $182.8 million for expansion capital. Also during 2012, we paid $37.5 million for growth projects in conjunction with our joint venture partners. During 2011, we spent $143.2 million for capital expenditures, which included $38.3 million for maintenance capital and $104.9 million for expansion capital. Also during 2011, we acquired the non-controlling owner's interest in one of our subsidiaries for $40.5 million and spent $17.8 million on various asset acquisitions.

Net cash used by financing activities for the nine months ended September 30, 2011 and 2012 was $29.5 million and $300.5 million, respectively. During 2012, we paid cash distributions of $293.8 million to our unitholders. During 2011, we received net proceeds of $260.9 million from borrowings under notes, which were used to repay the outstanding balance on our revolving credit facility of $193.0 million at that time, with the balance used for general partnership purposes. Additionally, we paid cash distributions of $260.7 million to our unitholders while borrowings on our revolving credit facility of $178.0 million, prior to being repaid, were primarily used to finance expansion capital projects and acquisitions.

The quarterly distribution amount related to our third-quarter 2012 financial results (to be paid in fourth quarter 2012) is $0.485 per unit. If we meet management's targeted distribution growth of 18% for 2012 and the number of outstanding limited partner units remains at 226.2 million, total cash distributions of approximately $424.4 million will be paid to our unitholders related to 2012.

In January 2012, the cumulative amounts of the January 2009 equity-based incentive compensation award grants were settled by issuing 722,766 limited partner units and distributing those units to the participants. Associated tax withholdings of $13.0 million and employer taxes of $1.3 million were paid in January 2012.

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 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 nine months ended September 30, 2011 and 2012, our maintenance capital spending was $38.3 million and $47.2 million, respectively. The pace of spending on projects in the current year has been accelerated from 2011; however, by the end of 2012 we expect to incur maintenance capital expenditures for our existing businesses of approximately $65.0 million, which would be lower than the $70.0 million we spent in 2011.

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During the first nine months of 2012, we spent $182.8 million for organic growth capital and $37.5 million for growth projects in conjunction with our joint venture partners. Based on the progress of expansion projects already underway, including the reversal and conversion of our Crane-to-Houston pipeline from refined products to crude oil service, we expect to spend approximately $450.0 million for expansion capital during 2012, with an additional $280.0 million in 2013 to complete these projects.

Liquidity

Consolidated debt at December 31, 2011 and September 30, 2012 was as follows (in millions):

	December 31, 2011	September 30, 2012	Weighted-Average Interest Rate at September 30, 2012 (1)
Revolving credit facility	$—	$—	—%
$250.0 million of 6.45% Notes due 2014	249.8	249.9	6.3%
$250.0 million of 5.65% Notes due 2016	252.0	251.7	5.6%
$250.0 million of 6.40% Notes due 2018	263.5	261.9	5.3%
$550.0 million of 6.55% Notes due 2019	578.5	575.9	5.7%
$550.0 million of 4.25% Notes due 2021	558.9	558.3	4.0%
$250.0 million of 6.40% Notes due 2037	249.0	249.0	6.4%
Total debt	$2,151.7	$2,146.7	5.3%

(1) Weighted-average interest rate includes the impact of 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 on interest expense.

The revolving credit facility and notes detailed in the table above are senior indebtedness.

The face value of our debt at December 31, 2011 and September 30, 2012 was $2.1 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. Realized gains and losses on fair value hedges and note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of those notes.

Revolving Credit Facility. The total borrowing capacity under our revolving credit facility, which matures in October 2016, is $800.0 million. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings and amounts outstanding under the facility. Additionally, an unused commitment fee is assessed at a rate from 0.125% to 0.3%, depending on our credit ratings. The unused commitment fee was 0.2% at September 30, 2012. Borrowings under this facility may be used for general purposes, including capital expenditures. As of September 30, 2012, there were no borrowings outstanding under this facility; however, $5.0 million was obligated for letters of credit. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets, but decrease our borrowing capacity under the facility.

Interest Rate Derivatives.
During 2012, we entered into a total of $250.0 million of forward-starting interest rate swap agreements to hedge against the variability of future interest payments on debt that we anticipate issuing between December 1, 2013 and December 1, 2014 to refinance our $250.0 million of 6.45% notes due June 1, 2014. Under the terms of these

agreements, we will pay a weighted-average fixed interest rate of 2.6% and receive LIBOR beginning June 1, 2014. The hedges have a 30-year maturity, which matches the expected maturity of the anticipated debt issuance; however, the hedges have a mandatory settlement date of June 1, 2014. We account for these agreements as cash flow hedges. At September 30, 2012, the fair value of these agreements was a gain of $11.1 million, which we recorded to accumulated other comprehensive loss.

Off-Balance Sheet Arrangements

None.

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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 Liability

Section 185 of the Clean Air Act ("CAA 185") requires states under certain conditions to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas 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 administer and enforce 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") is currently considering a “Failure to Attain Rule” to implement the requirements of CAA 185. The draft Failure to Attain Rule is anticipated to be adopted in the spring of 2013 and is expected to provide for the collection of an annual failure to attain fee for excess emissions. We have certain facilities in the Houston area that we expect will be subject to the TCEQ's Failure to Attain Rule. We have recorded an accrual of $8.9 million related to this matter for the period of 2008 through 2010 with a possible range of loss from zero to $13.7 million. This accrual is reflected as a long-term environmental liability at September 30, 2012.

Stationary Engine Emission Standards

The EPA had set a May 2013 compliance date for the reduction of carbon monoxide from the exhausts of large stationary engines. The EPA rule generally anticipates the installation of catalytic converters to the engine exhaust to achieve compliance; however, engine replacements may be required if it is determined that catalytic converters will not achieve the required level of emission reductions. A portion of our petroleum pipeline system uses engines to provide power to our pipeline pumps that are subject to the EPA rule, and we are actively assessing the best option for compliance. We have received a one-year extension to modify or replace these engines. If we are not able to modify or replace these engines by May 2014, sections of our petroleum pipeline system could experience capacity reductions or we could be assessed penalties until the required emission reductions are achieved.

Other Items

Commodity Derivative Agreements. Certain of the business activities in which we engage result in our owning various commodities, which exposes us to commodity price risk. We use NYMEX contracts and butane swap agreements to help manage this commodity price risk. We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell in future periods. We use and account for those NYMEX contracts that qualify for hedge accounting treatment as either cash flow or fair value hedges, and we use and account for those NYMEX contracts that do not qualify for hedge accounting treatment as economic hedges. We use butane swap agreements to hedge against changes in the price of butane we expect to purchase in the future as part of our petroleum products blending activity. As of September 30, 2012, our open derivative contracts were as follows:

Open Derivative Contracts Designated as Hedges

- NYMEX contracts for 0.1 million barrels of petroleum products to hedge against price changes in anticipated sales of petroleum products related to our petroleum products blending and fractionation activities, which we are accounting for as cash flow hedges. These contracts mature in October 2012. Through September 30, 2012, the cumulative amount of unrealized losses from these agreements was $0.2 million, which did not impact product sales and was recorded as an adjustment to accumulated other comprehensive loss.

- NYMEX contracts covering 0.7 million barrels of crude oil to hedge against future price changes of crude linefill and tank bottom inventory. These contracts, which we are accounting for as fair value hedges, mature between October 2012 and November 2013. Through September 30, 2012, the cumulative amount of unrealized losses from these agreements was $5.4 million. The unrealized losses from these fair value hedges were recorded as adjustments to the

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asset being hedged and, as a result, none of these unrealized losses impacted product sales.

Open Derivative Contracts Not Designated as Hedges

- NYMEX contracts covering 2.0 million barrels of petroleum products related to our petroleum products blending, fractionation and Houston-to-El Paso linefill management activities. These contracts mature between October 2012 and April 2013 and are being accounted for as economic hedges. Through September 30, 2012, the cumulative amount of net unrealized losses associated with these agreements was $10.5 million, of which all were recognized in 2012.

- NYMEX contracts covering 0.4 million barrels of petroleum products related to our pipeline product overages that mature between October 2012 and January 2013, which are being accounted for as economic hedges. Through September 30, 2012, the cumulative amount of unrealized losses associated with these agreements was $0.9 million. We recorded these losses as an increase in operating expenses, all of which was recognized during 2012.

- Butane swap agreements to purchase 0.4 million barrels of butane that mature between October 2012 and April 2013, which are being accounted for as economic hedges. Through September 30, 2012, the cumulative amount of unrealized losses associated with these agreements was $1.1 million. We recorded these losses as an increase in product purchases, all of which was recognized in 2012.

Settled Derivative Contracts

Related to physical product sales during 2012, we recognized losses of $29.0 million on NYMEX contracts that did not qualify for hedge accounting treatment that settled during 2012.

Additionally, we recognized gains of $1.4 million on NYMEX contracts that settled during 2012 related to physical product sales during the third quarter of 2012.

Product Sales Revenues

The following tables provide a summary of the mark-to-market gains and losses associated with NYMEX contracts and the accounting periods in which the gains and losses impacted product sales revenues in our consolidated statements of income for the three and nine months ended September 30, 2011 and 2012 (in millions):

Three Months Ended September 30, 2011		
NYMEX gains recorded during the three months ended September 30, 2011 that were associated with physical product sales during the three months ended September 30, 2011	$5.9	
NYMEX gains recorded during the three months ended September 30, 2011 that were associated with future physical product sales	24.2	
NYMEX gains which impacted product sales revenues during the three months ended September 30, 2011	$30.1	
Three Months Ended September 30, 2012		
NYMEX losses recorded during the three months ended September 30, 2012 that were associated with physical product sales during the three months ended September 30, 2012	$(15.2	)
NYMEX losses recorded during the three months ended September 30, 2012 that were associated with future physical product sales	(28.1	)
NYMEX losses which impacted product sales revenues during the three months ended September 30, 2012	$(43.3	)

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Nine Months Ended September 30, 2011	
NYMEX losses recorded during the nine months ended September 30, 2011 that were associated with physical product sales during the nine months ended September 30, 2011	$(32.7)
NYMEX gains recorded during the nine months ended September 30, 2011 that were associated with future physical product sales	26.6
Net NYMEX losses which impacted product sales revenues during the nine months ended September 30, 2011	$(6.1)
Nine Months Ended September 30, 2012	
NYMEX losses recorded during the nine months ended September 30, 2012 that were associated with physical product sales during the nine months ended September 30, 2012	$(27.6)
NYMEX losses recorded during the nine months ended September 30, 2012 that were associated with future physical product sales	(10.5)
NYMEX losses which impacted product sales revenues during the nine months ended September 30, 2012	$(38.1)

Pipeline Conversion to Crude Service. We are in the process of reversing and converting to crude oil service our pipeline from Crane, Texas to our East Houston, Texas terminal for a cost of $375.0 million. The 225,000 barrel-per-day ("bpd") capacity of the pipeline is fully committed with long-term agreements. Subject to receiving the necessary permits and regulatory approvals, we expect the reversed pipeline to begin transporting crude oil at partial capacity by early 2013, increasing to its full 225,000 bpd capacity by mid-2013.

We have discontinued the pipeline linefill activities that we were conducting in connection with the current service for this pipeline. We have sold approximately 0.4 million barrels of the linefill and intend to liquidate the remainder of the linefill. At September 30, 2012, we owned 0.3 million barrels of refined petroleum products linefill inventory with a carrying value of approximately $39.6 million. We continue to economically hedge this inventory with NYMEX futures contracts, which we will unwind as this inventory is physically sold.

Osage Complaint. In June 2012, HollyFrontier Refining & Marketing LLC ("HollyFrontier") filed a complaint with the Federal Energy Regulatory Commission alleging that Osage Pipe Line Company, LLC ("Osage") has been over-earning on its rates for transportation on Osage's crude oil pipeline system from Cushing, Oklahoma to El Dorado, Kansas. We own 50% of Osage and serve as its operator. We believe that it is reasonably possible that Osage could incur a liability as a result of this complaint. As the 50% owner of Osage, we currently estimate that our ultimate exposure in this matter will be within a range of zero to approximately $6.3 million. We believe the claims should be denied and are defending the Osage rates vigorously. As of September 30, 2012, neither we nor Osage had any amounts accrued for this matter.

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 $3.4 million as of September 30, 2012. 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.

Related Party Transactions. We own a 50% interest in Osage and receive a management fee for the operation of its crude oil pipeline. We received management fees from this company of $0.2 million for each of the three months ended September 30, 2011 and 2012, and $0.6 million for each of the nine months ended September 30, 2011 and 2012. We reported these fees as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in Texas Frontera, LLC ("Texas Frontera"), which has constructed 0.8 million barrels of refined products storage at our Galena Park, Texas terminal. These tanks, which began operation in October 2012, are leased to an affiliate of Texas Frontera under a long-term lease agreement. Additionally, we have constructed certain infrastructure assets at our Galena Park terminal which allow for the operation of the Texas Frontera tanks. For the nine months ended September 30, 2012, we contributed $3.9 million to Texas Frontera, of which we paid $2.5 million in cash and contributed assets of $1.4 million.

We own a 50% interest in Double Eagle Pipeline LLC ("Double Eagle"), which is in the process of constructing a 140-mile pipeline that will connect to an existing pipeline segment owned by an affiliate of Double Eagle. Once completed, Double

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Eagle will transport condensate from the Eagle Ford shale formation to our terminal in Corpus Christi, Texas. For the nine months ended September 30, 2012, we contributed $34.5 million for construction funding requests from Double Eagle. We expect these assets to be fully operational in mid-2013.

Barry R. Pearl is an independent member of our general partner's board of directors and is also a director of Targa Resources Partners, L.P. ("Targa"). In the normal course of business, we purchase petroleum products from subsidiaries of Targa. For the three months ended September 30, 2011 and 2012, respectively, we made purchases of petroleum products from subsidiaries of Targa of less than $0.1 million. For the nine months ended September 30, 2011 and 2012, we made purchases of petroleum products from subsidiaries of Targa of $0.3 million and $12.5 million, respectively. These purchases were made on the same terms as comparable third-party transactions.

In January 2011, our former chief executive officer, Don R. Wellendorf, retired. In conjunction with Mr. Wellendorf's retirement, our general partner's board of directors engaged Mr. Wellendorf as a consultant to us for a period of twelve months beginning in February 2011 for consideration of $0.3 million and an agreement that certain of his previously-awarded phantom unit awards would not be forfeited. Expense associated with these awards for the nine months ended September 30, 2011 and 2012 was $1.9 million and $0.4 million, respectively.

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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 us manage commodity price risk. Forward contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting. As of September 30, 2012, we had commitments under forward purchase and sale contracts used in our blending and fractionation activities as follows (in millions):

	Value	Barrels
Forward purchase contracts	$79.6	0.8
Forward sale contracts	$71.1	0.6

We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell from activities in which 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, or are otherwise undesignated as cash flow or fair value hedges, as economic hedges. We also use butane swap agreements to hedge against changes in the price of butane that we expect to purchase in future periods. At September 30, 2012, we had open NYMEX contracts representing 3.2 million barrels of petroleum products we expect to sell in the future. Additionally, we had open butane swap agreements for 0.4 million barrels of butane we expect to purchase in the future.

At September 30, 2012, the fair value of our open NYMEX contracts was a net liability of $17.0 million and the fair value of our butane swap agreements was a liability of $1.1 million. Combined, the net liability was $18.1 million, of which $12.6 million was recorded as a current liability to energy commodity derivatives contracts and $5.5 million was recorded as other noncurrent liabilities on our consolidated balance sheet.

At September 30, 2012, open NYMEX contracts representing 2.4 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 $2.4 million decrease in our operating profit and a $1.00 per barrel decrease in the price of these NYMEX contracts for RBOB or heating oil would result in a $2.4 million increase in our operating profit. However, the increases or decreases in operating profit we recognize from our open NYMEX contracts will be substantially offset by higher or lower product sales revenues when the physical sale 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.

At September 30, 2012, open butane swap agreements representing 0.4 million barrels of butane were designated as economic hedges. A $1.00 per barrel increase in the price of butane would result in a $0.4 million decrease in our product purchases and a $1.00 per barrel decrease in the price of butane would result in a $0.4 million increase in our product purchases. However, the increases or decreases in product purchases we recognize from our open butane swap contracts will be substantially offset by higher or lower product purchases when the physical 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

As of September 30, 2012, we entered into a total of $250.0 million of forward-starting interest rate swap agreements to hedge against the variability of future interest payments on debt that we anticipate issuing between December 1, 2013 and December 1, 2014 to refinance our $250.0 million of 6.45% notes due June 1, 2014. Under the terms of these agreements, we will pay a weighted-average fixed interest rate of 2.6% and receive LIBOR. The hedges have a 30-year maturity, which matches the expected maturity of the anticipated debt issuance; however, the hedges have a mandatory settlement date of June 1, 2014. We account for these agreements as cash flow hedges. A 0.125% increase in interest rates would result in an increase in the fair value of these agreements of approximately $6.3 million. A 0.125% decrease in interest rates would result in a decrease in the fair value of these agreements of approximately $6.5 million.

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At September 30, 2012, we had no variable rate debt outstanding, including on our revolving credit facility. Our revolving credit facility has total borrowing capacity of $800.0 million, from which we could borrow in the future. To the extent we borrow funds under this facility in any future period, those borrowings would bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings and amounts outstanding under the facility.

ITEM 4. CONTROLS AND PROCEDURES

We performed 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) as of the end of the period covered by the date of this report. We performed this evaluation 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 September 30, 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Forward-Looking Statements

Certain matters discussed in this Quarterly Report on Form 10-Q include forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act that discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as "anticipates," "believes," "continue," "could," "estimates," "expects," "forecasts," "goal," "guidance," "intends," "may," "might," "plans," "potential," "projects," "scheduled," "should" and other similar expressions. Although we believe our forward-looking statements are based on reasonable assumptions, statements made regarding future results are not guarantees of future performance and 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, crude oil, natural gas liquids and ammonia in the U.S.;
- price fluctuations for refined petroleum products, crude oil, natural gas liquids and ammonia 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, joint venture partners 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, including but not limited to, solar power, wind power and geothermal energy, increased use of biofuels such as ethanol and biodiesel, increased conservation or fuel efficiency, as well as 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;
- changes in supply patterns for our storage terminals due to geopolitical events;
- our ability to manage interest rate and commodity price exposures;
- changes in our tariff rates implemented by the Federal Energy Regulatory Commission, the U.S. Surface Transportation Board or state regulatory agencies;

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- shut-downs or cutbacks at refineries, petrochemical plants, ammonia production facilities or other customers or businesses that use or supply our services;
- the effect of weather patterns and other natural phenomena, including climate change, on our operations and demand for our services;
- an increase in the competition our operations encounter;
- the occurrence of natural disasters, terrorism, operational hazards, equipment failures, system failures 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 joint ventures and successfully complete our business strategy;
- uncertainty of estimates, including accruals and costs of environmental remediation;
- actions by rating agencies concerning our credit ratings;
- our ability to timely obtain and maintain all necessary approvals, consents and permits required to operate our existing assets and any new or modified assets;
- our ability to promptly obtain all necessary materials, supplies and rights-of-way required for construction, and to construct facilities without labor or contractor problems;
- risks inherent in the use and security of information systems in our business and implementation of new software and hardware;
- 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 become subject, including tax withholding issues, safety, security, 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, 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;
- the ability of third parties to perform on their contractual obligations to us;
- petroleum product supply disruptions;
- global and domestic economic repercussions from terrorist activities and the government's response thereto; and
- other factors and uncertainties inherent in the transportation, storage and distribution of petroleum products.

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, we received an information request from the U.S. Environmental Protection Agency ("EPA"), pursuant to Section 308 of the Clean Water Act, regarding a pipeline release in February 2011 in Texas. We have accrued $0.1 million for potential monetary sanctions related to this matter. 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.

In March 2012, we received a Notice of Probable Violation from the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration for alleged violations related to the operation and maintenance of certain pipelines in Oklahoma and Texas. We have accrued approximately $0.1 million for potential monetary sanctions related to this matter. 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.

In April 2012, we received an information request from the EPA pursuant to Section 308 of the Clean Water Act, regarding a pipeline release in December 2011 in Nebraska. We have accrued $0.6 million for potential monetary sanctions related to this matter. 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.

In August 2012, we entered into an agreed order with the Texas Commission on Environmental Quality to settle three outstanding air quality notices of violation received over a three year period, pursuant to which we paid a total civil penalty of approximately $0.1 million.

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 results of operations, financial position 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, 2011, 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. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

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ITEM 6. EXHIBITS

Exhibit Number		Description
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 November 1, 2012.

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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