MAGELLAN MIDSTREAM PARTNERS LP
Form 10-Q
May 03, 2013

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 March 31, 2013

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 May 2, 2013, there were 226,679,438 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 March 31,	
	2012	2013
Transportation and terminals revenues	$217,554	$227,271
Product sales revenues	275,730	201,711
Affiliate management fee revenue	199	3,439
Total revenues	493,483	432,421
Costs and expenses:		
Operating	68,452	65,181
Product purchases	248,612	160,398
Depreciation and amortization	31,510	36,332
General and administrative	23,744	30,056
Total costs and expenses	372,318	291,967
Earnings of non-controlled entities	1,648	2,051
Operating profit	122,813	142,505
Interest expense	29,123	31,723
Interest income	(35)	(22)
Interest capitalized	(864)	(3,451)
Debt placement fee amortization expense	519	540
Income before provision for income taxes	94,070	113,715
Provision for income taxes	546	748
Net income	$93,524	$112,967
Basic and diluted net income per limited partner unit	$0.41	$0.50
Weighted average number of limited partner units outstanding used for basic and diluted net income per unit calculation	226,182	226,705

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 March 31,	
	2012	2013
Net income	$93,524	$112,967
Other comprehensive income:		
Net loss on commodity cash flow hedges	—	(4,560)
Reclassification of net gain on interest rate cash flow hedges to interest expense(1)	(41)	(41)
Reclassification of net loss on commodity hedges to product sales revenues(1)	—	4,408
Changes in employee benefit plan assets and benefit obligations(2)	852	479
Total other comprehensive income	811	286
Comprehensive income	$94,335	$113,253

1) See Note 8–Derivative Financial Instruments for additional information on amounts reclassified from accumulated other comprehensive loss into income.
2) These accumulated other comprehensive income components are included in the computation of net periodic pension cost (see Note 6–Employee Benefit Plans).

See notes to consolidated financial statements.

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

	December 31, 2012	March 31, 2013 (Unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$ 328,278	$ 221,003
Trade accounts receivable (less allowance for doubtful accounts of $5 and $4 at December 31, 2012 and March 31, 2013, respectively)	91,114	110,756
Other accounts receivable	12,329	9,520
Inventory	221,888	205,152
Energy commodity derivatives deposits	18,304	14,592
Reimbursable costs	4,863	3,401
Other current assets	23,502	21,071
Total current assets	700,278	585,495
Property, plant and equipment	4,408,550	4,495,232
Less: accumulated depreciation	943,248	974,345
Net property, plant and equipment	3,465,302	3,520,887
Investments in non-controlled entities	107,356	155,563
Long-term receivables	5,135	4,563
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of $16,715 and $10,491 at December 31, 2012 and March 31, 2013, respectively)	13,274	9,398
Debt placement costs (less accumulated amortization of $7,886 and $8,426 at December 31, 2012 and March 31, 2013, respectively)	15,080	14,552
Tank bottom inventory	58,493	60,270
Other noncurrent assets	1,889	1,725
Total assets	$ 4,420,067	$ 4,405,713
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 112,002	$ 111,449
Accrued payroll and benefits	32,434	21,721
Accrued interest payable	42,059	37,406
Accrued taxes other than income	33,089	27,291
Environmental liabilities	14,442	15,149
Deferred revenue	46,371	57,018
Accrued product purchases	72,049	78,322
Energy commodity derivatives contracts, net	7,338	5,089
Other current liabilities	32,836	28,628
Total current liabilities	392,620	382,073
Long-term debt	2,393,408	2,391,718
Long-term pension and benefits	68,134	72,481
Other noncurrent liabilities	16,382	15,259
Environmental liabilities	33,821	31,645
Commitments and contingencies		
Partners’ capital:		

Limited partner unitholders (226,201 units and 226,679 units outstanding at December 31, 2012 and March 31, 2013, respectively)	1,550,760	1,547,309
Accumulated other comprehensive loss	(35,058)	(34,772)
Total partners' capital	1,515,702	1,512,537
Total liabilities and partners' capital	$ 4,420,067	$4,405,713

See notes to consolidated financial statements.

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

	Three Months Ended March 31, 2012	2013
Operating Activities:		
Net income	$93,524	$112,967
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	31,510	36,332
Debt placement fee amortization	519	540
Loss on sale, retirement and impairment of assets	5,407	1,791
Earnings of non-controlled entities	(1,648)	(2,051)
Distributions from investments in non-controlled entities	1,648	676
Equity-based incentive compensation expense	2,843	4,856
Changes in employee benefit plan assets and benefit obligations	852	479
Changes in operating assets and liabilities:		
Trade accounts receivable and other accounts receivable	(22,814)	(16,833)
Inventory	18,693	16,736
Energy commodity derivatives contracts, net of derivatives deposits	(8,358)	1,311
Reimbursable costs	1,085	1,462
Accounts payable	(16,863)	11,310
Accrued payroll and benefits	(13,984)	(10,713)
Accrued interest payable	(7,288)	(4,653)
Accrued taxes other than income	(5,707)	(5,798)
Accrued product purchases	7,705	6,273
Deferred revenue	2,010	10,647
Current and noncurrent environmental liabilities	(2,109)	(1,469)
Other current and noncurrent assets and liabilities	2,716	5,915
Net cash provided by operating activities	89,741	169,778
Investing Activities:		
Property, plant and equipment:		
Additions to property, plant and equipment	(37,139)	(89,947)
Proceeds from sale and disposition of assets	40	25
Decrease in accounts payable related to capital expenditures	(1,979)	(11,863)
Investments in non-controlled entities	(3,655)	(47,020)
Distributions in excess of earnings of non-controlled entities	870	188
Net cash used by investing activities	(41,863)	(148,617)
Financing Activities:		
Distributions paid	(92,177)	(113,340)
Decrease in outstanding checks	(678)	(2,837)
Settlement of tax withholdings on long-term incentive compensation	(13,001)	(12,259)
Net cash used by financing activities	(105,856)	(128,436)
Change in cash and cash equivalents	(57,978)	(107,275)
Cash and cash equivalents at beginning of period	209,620	328,278
Cash and cash equivalents at end of period	$151,642	$221,003
Supplemental non-cash financing activity:		

Issuance of limited partner units in settlement of equity-based incentive plan awards	$7,295	$6,404

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.

During first quarter 2013, we completed a reorganization of our reporting segments. This reorganization was effected to reflect strategic changes in our businesses, particularly in the area of our crude oil activities, which have had or will have a significant impact on the way we manage our operations. Accordingly, we have updated our segment disclosures for all previous periods included in this report. Our reportable segments offer different products and services and are managed separately because each requires different marketing strategies and business knowledge.

Basis of Presentation

In the opinion of management, our accompanying consolidated financial statements which are unaudited, except for the consolidated balance sheet as of December 31, 2012, which is derived from our audited financial statements, include all normal and recurring adjustments necessary to present fairly our financial position as of March 31, 2013, the results of operations for the three months ended March 31, 2012 and 2013 and cash flows for the three months ended March 31, 2012 and 2013. The results of operations for the three months ended March 31, 2013 are not necessarily indicative of the results to be expected for the full year ending December 31, 2013.

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, 2012 and the updates to our Annual Report reflecting changes in our reporting segments on Form 8-K filed with the Securities and Exchange Commission on April 29, 2013.

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 from mark-to-market adjustments from New York Mercantile Exchange ("NYMEX") contracts. We use NYMEX contracts to hedge against changes in the price of refined products we expect to sell from our business activities where we acquire or produce petroleum products. Some of these NYMEX contracts qualify for hedge accounting treatment and we designate and account for these as either cash flow or fair value hedges. The effective portion of the fair value changes in contracts designated as cash flow hedges are recognized as adjustments to product sales when the hedged product is physically sold. Ineffectiveness in the contracts designated as cash flow hedges is recognized as an adjustment to product sales in the period the ineffectiveness occurs. 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, except for those agreements that economically hedge the inventories associated with our pipeline system overages (the period changes in the fair value of these agreements are charged to operating expense). See Note 8 - Derivative Financial Instruments for further disclosures regarding our NYMEX contracts.

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

For the three months ended March 31, 2012 and 2013, product sales revenues included the following (in thousands):

	Three Months Ended March 31,	
	2012	2013
Physical sale of petroleum products	$307,706	$207,880
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 butane blending and fractionation activities(1)	(24,889)	(6,158)
Change in value of NYMEX contracts that did not qualify for hedge accounting treatment associated with the Houston-to-El Paso pipeline linefill working inventory(1)	(7,099)	—
Other	12	(11)
Total NYMEX contract adjustments	(31,976)	(6,169)
Total product sales revenues	$275,730	$201,711

(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

During the first quarter of 2013, we revised our reporting segments. See Note 1—Organization and Basis of Presentation for a discussion of this matter.

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 earnings of non-controlled entities. 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 March 31, 2012 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenues	$157,670	$21,213	$38,671	$—	$217,554
Product sales revenues	272,818	—	2,912	—	275,730
Affiliate management fee revenue	—	199	—	—	199
Total revenues	430,488	21,412	41,583	—	493,483
Operating expenses[1]	57,206	(897)	12,877	(734)	68,452
Product purchases	247,836	—	776	—	248,612
(Earnings) losses of non-controlled entities	—	(1,668)	20	—	(1,648)
Operating margin	125,446	23,977	27,910	734	178,067
Depreciation and amortization expense	21,057	3,162	6,557	734	31,510
G&A expenses	19,037	1,121	3,586	—	23,744
Operating profit	$85,352	$19,694	$17,767	$—	$122,813

	Three Months Ended March 31, 2013 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenues	$165,359	$23,228	$38,684	$—	$227,271
Product sales revenues	199,415	—	2,296	—	201,711
Affiliate management fee revenue	—	3,159	280	—	3,439
Total revenues	364,774	26,387	41,260	—	432,421
Operating expenses	46,281	5,107	14,553	(760)	65,181
Product purchases	158,298	—	2,100	—	160,398
Earnings of non-controlled entities	—	(1,375)	(676)	—	(2,051)
Operating margin	160,195	22,655	25,283	760	208,893
Depreciation and amortization expense	21,353	7,469	6,750	760	36,332
G&A expenses	21,202	4,127	4,727	—	30,056
Operating profit	$117,640	$11,059	$13,806	$—	$142,505

(1) Product overages more than offset other operating expenses for the crude oil segment in the first quarter of 2012.

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4. Investments in Non-Controlled Entities

We own a 50% interest in Osage Pipe Line Company, LLC ("Osage") and receive a management fee for the operation of its crude oil pipeline. We received management fees from Osage which we reported as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in Texas Frontera, LLC ("Texas Frontera"), which owns 0.8 million barrels of refined products storage at our Galena Park, Texas terminal. This storage capacity, which began operation in October 2012, is leased to an affiliate of Texas Frontera under a long-term lease agreement. We received management fees from Texas Frontera which we reported as affiliate management fee revenue on our consolidated statements of income.

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 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. We expect these assets to be fully operational in the third quarter of 2013.

We own a 50% interest in BridgeTex Pipeline Company, LLC ("BridgeTex"), which is in the process of constructing a 450-mile pipeline and related infrastructure to transport crude oil from Colorado City, Texas for delivery to Houston and Texas City, Texas refineries. This pipeline is expected to begin service in mid-2014. We received construction management fees from BridgeTex which we reported as affiliate management fee revenue on our consolidated statements of income.

A summary of our investments in non-controlled entities follows (in thousands):

	Texas Frontera	Osage	Double Eagle	BridgeTex	Consolidated
Investment at December 31, 2012	$15,728	$18,888	$40,840	$31,900	$107,356
Additional investment	—	—	20,692	26,328	47,020
Earnings (losses) of non-controlled entities:					
Proportionate share of earnings (losses)	676	1,711	(170)	—	2,217
Amortization of excess investment	—	(166)	—	—	(166)
Earnings (losses) of non-controlled entities	676	1,545	(170)	—	2,051
Less:					
Distributions from investments in non-controlled entities	676	—	—	—	676
Distributions in excess of earnings of non-controlled entities	188	—	—	—	188
Investment at March 31, 2013	$15,540	$20,433	$61,362	$58,228	$155,563

The operating results from Texas Frontera are included in our marine storage segment and the operating results from Osage, Double Eagle and BridgeTex are included in our crude oil segment.

Our initial investment in Osage included an excess net investment amount of $21.7 million. Excess investment is the amount by which our initial investment exceeded our proportionate share of the book value of the net assets of the investment. The unamortized excess net investment amount at March 31, 2013 was $15.6 million.

5. Inventory

Inventory at December 31, 2012 and March 31, 2013 was as follows (in thousands):

	December 31, 2012	March 31, 2013
Refined products	$88,630	$71,755
Liquefied petroleum gases	45,657	48,128
Transmix	63,026	63,040
Crude oil	17,443	15,539
Additives	7,132	6,690
Total inventory	$221,888	$205,152

6. Employee Benefit Plans

We sponsor two union pension plans for certain union 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 the pension and postretirement benefit plans for the three months ended March 31, 2012 and 2013 (in thousands):

	Three Months Ended March 31, 2012		Three Months Ended March 31, 2013	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of net periodic benefit costs:				
Service cost	$3,190	$138	$3,576	$77
Interest cost	1,203	257	1,350	115
Expected return on plan assets	(1,176)	—	(1,470)	—
Amortization of prior service cost (credit)(1)	77	(213)	77	(928)
Amortization of actuarial loss(1)	827	161	1,022	308
Net periodic benefit cost (credit)	$4,121	$343	$4,555	$(428)

(1) These amounts are included in our Consolidated Statements of Comprehensive Income as changes in employee benefit plan assets and benefit obligations.

7. Debt

Consolidated debt at December 31, 2012 and March 31, 2013 was as follows (in thousands):

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

	December 31, 2012	March 31, 2013	Weighted-Average Interest Rate at March 31, 2013 (a)
Revolving credit facility	$—	$—	—%
$250.0 million of 6.45% Notes due 2014	249,905	249,921	6.3%
$250.0 million of 5.65% Notes due 2016	251,609	251,502	5.7%
$250.0 million of 6.40% Notes due 2018	261,411	260,895	5.3%
$550.0 million of 6.55% Notes due 2019	575,065	574,187	5.7%
$550.0 million of 4.25% Notes due 2021	558,088	557,872	4.0%
$250.0 million of 6.40% Notes due 2037	248,981	248,985	6.4%
$250.0 million of 4.20% Notes due 2042	248,349	248,356	4.2%
Total debt	$2,393,408	$2,391,718	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.

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

The face value of our debt at December 31, 2012 and March 31, 2013 was $2.4 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 March 31, 2013. Borrowings under this facility may be used for general purposes, including capital expenditures. As of March 31, 2013, there were no borrowings outstanding under this facility; however, $5.6 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.

8. Derivative Financial Instruments

Commodity Derivatives

Our butane 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 futures agreements to help manage price changes, which has the effect of locking in most of the product margin realized from our butane blending activities that we choose to hedge.

We account for the forward physical purchase and sale contracts we use in our butane 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 March 31, 2013, we had commitments under these forward purchase and sale contracts as follows (in millions):

	Value	Barrels
Forward purchase contracts	$7.8	0.1
Forward sale contracts	$29.9	0.3

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 exchange-traded butane futures 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.

Additionally, we currently hold petroleum product inventories that we obtained from overages on our pipeline systems. We use NYMEX contracts, which are not designated as hedges for accounting purposes, to help manage price changes related to these overage inventory barrels. Changes in the fair value of these agreements are recognized currently in earnings as adjustments to operating expense.

As outlined in the table below, our open NYMEX contracts and butane futures agreements at March 31, 2013 were as follows:

Type of Contract/Accounting Methodology	Product Represented by the Contract and Associated Barrels	Maturity Dates
NYMEX - Fair Value Hedges	0.7 million barrels of crude oil	Between April and November 2013
NYMEX - Economic Hedges	1.4 million barrels of refined products and crude oil	Between April and October 2013
Butane Futures Agreements - Economic Hedges	less than 0.1 million barrels of butane	April 2013

At March 31, 2013, we had margin deposits of $14.6 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 futures agreements against our margin deposits under a master netting arrangement; however, we have elected to disclose the combined fair values of our open NYMEX and butane futures 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 futures agreements together for each counterparty, which we have elected to do, and we report the combined net balances on our consolidated balance sheets. A schedule of the derivative amounts we have offset and the deposit amounts we could offset under a master netting arrangement are provided below as of December 31, 2012 and March 31, 2013 (in thousands):

	December 31, 2012				
Description	Gross Amounts of Recognized Liabilities	Gross Amounts of Assets Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheet	Net Amount
Derivative-related balances	$(9,388)	$2,050	$(7,338)	$18,304	$10,966

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

	March 31, 2013				
Description	Gross Amounts of Recognized Liabilities	Gross Amounts of Assets Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheet	Net Amount
Derivative-related balances	$(5,106)	$17	$(5,089)	$14,592	$9,503

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 months ended March 31, 2012 and 2013 were as follows (in thousands):

	Three Months Ended March 31,	
Derivative Gains (Losses) Included in AOCL	2012	2013
Beginning balance	$3,161	$14,126
Net loss on commodity cash flow hedges	—	(4,560)
Reclassification of net gain on interest rate cash flow hedges to interest expense	(41)	(41)
Reclassification of net loss on commodity hedges to product sales revenues	—	4,408
Ending balance	$3,120	$13,933

As of March 31, 2013, the net gain estimated to be classified to interest expense over the next twelve months from AOCL is approximately $0.2 million.

During first quarter 2013, we had open NYMEX contracts on 0.7 million barrels of crude oil that were designated as fair value hedges. These agreements hedge against the change in value of our crude oil linefill and tank bottom inventory. Because there was no ineffectiveness recognized on these hedges, the cumulative losses of $7.1 million from the agreements as of March 31, 2013 were fully offset by a cumulative increase of $7.3 million to tank bottom inventory and a cumulative decrease of $0.2 million to our crude oil linefill, which is reported in 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 months ended March 31, 2012 and 2013 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 March 31, 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	$—	Interest expense	$ 41

	Three Months Ended March 31, 2013		
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Gain (Loss) Reclassified from AOCL into Income	Amount of Gain (Loss) Reclassified from AOCL into Income
Interest rate swap agreements	$—	Interest expense	$ 41
NYMEX commodity contracts	(4,560)	Product sales revenues	(4,408)

Total cash flow hedges	$(4,560)	Total	$ (4,367)

There was no ineffectiveness recognized on the financial instruments disclosed in the above tables during the three months ended March 31, 2012 or 2013.

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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 months ended March 31, 2012 and 2013 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	
Derivative Instrument	Location of Gain (Loss) Recognized on Derivative	March 31, 2012	March 31, 2013
NYMEX commodity contracts	Product sales revenues	$(31,976)	$(1,761)
NYMEX commodity contracts	Operating expenses	(5,184)	(1,886)
Butane futures agreements	Product purchases	43	(781)
	Total	$(37,117)	$(4,428)

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, 2012 and March 31, 2013 (in thousands):

	December 31, 2012			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$473	Energy commodity derivatives contracts, net	$207

	March 31, 2013			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$—	Energy commodity derivatives contracts, net	$1,808

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, 2012 and March 31, 2013 (in thousands):

	December 31, 2012			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$227	Energy commodity derivatives contracts, net	$8,954
Butane futures agreements	Energy commodity derivatives contracts, net	1,350	Energy commodity derivatives contracts, net	227
	Total	$1,577	Total	$9,181

	March 31, 2013			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value

NYMEX commodity contracts	Energy commodity derivatives contracts, net	$—	Energy commodity derivatives contracts, net	$3,298
Butane futures agreements	Energy commodity derivatives contracts, net	17	Energy commodity derivatives contracts, net	—
	Total	$17	Total	$3,298

9. Commitments and Contingencies

Clean Air Act - Section 185 Liability

Section 185 of the Clean Air Act ("CAA 185") requires states to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas that did not meet the attainment deadline. The CAA 185 fees are required annually 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 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 will be subject to the TCEQ's Failure to Attain Rule.

Management believes the most likely scenario is that we will be assessed fees for excess emissions at our Houston area facilities and our estimate of the possible range of loss associated with this matter is from zero to $14.3 million. As of March 31, 2013, we have accrued $11.1 million as a long-term environmental liability related to this matter. The final Failure to Attain Rule is expected to be published in 2013; therefore, it is reasonably possible that our estimate of this loss will change in the near term.

Potential Responsible Party in a Pasadena, Texas Superfund Site

In December 2012, we received a notice from the EPA that we may have potential liability at the U.S. Oil Recovery Superfund Site in Pasadena, Texas as a potential responsible party under Section 107(a) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended. Currently, there is an ongoing removal action designed to stabilize the site, remove the immediate threat posed at the site and set the stage for a later more comprehensive action. Due to the timing of the EPA's notice, we are unable at this point, to reasonably estimate the amount of our liability related to this matter.

Environmental Liabilities

Liabilities recognized for estimated environmental costs were $48.3 million and $46.8 million at December 31, 2012 and March 31, 2013, 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 $2.5 million and $0.7 million for the three months ended March 31, 2012 and 2013, respectively.

Environmental Receivables

Receivables from insurance carriers and other third parties related to environmental matters at December 31, 2012 were $7.9 million, of which $2.8 million and $5.1 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheet. Receivables from insurance carriers and other third parties related to environmental matters at March 31, 2013 were $7.3 million, of which $2.7 million and $4.6 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheet.

Other

We are a party to various other claims, legal actions and complaints arising in the ordinary course of business, including without limitation those disclosed in Item 1, Legal Proceedings of Part II of this report on Form 10-Q. 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.

10. 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 March 31, 2013, 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 March 31, 2013 total 1.8 million. The compensation committee of our general partner's board of directors administers our LTIP.

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

	Three Months Ended March 31, 2012		
	Equity Method	Liability Method	Total
Performance-based awards:			
2010 awards	$522	$408	$930
2011 awards	743	273	1,016
2012 awards	561	151	712
Retention awards	185	—	185
Total	$2,011	$832	$2,843
Allocation of LTIP expense on our consolidated statements of income:			
G&A expense			$2,505
Operating expense			338
Total			$2,843

	Three Months Ended March 31, 2013		
	Equity Method	Liability Method	Total
Performance-based awards:			
2010 awards	$121	$73	$194
2011 awards	983	1,147	2,130
2012 awards	881	611	1,492
2013 awards	726	189	915
Retention awards	125	—	125
Total	$2,836	$2,020	$4,856
Allocation of LTIP expense on our consolidated statements of income:			
G&A expense			$4,485
Operating expense			371
Total			$4,856

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

11. Distributions

Distributions we paid during 2012 and 2013 were as follows (in thousands, except per unit amounts):

Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution to Limited Partners
2/14/2012	$0.40750	$92,177
5/15/2012	0.42000	95,004
8/14/2012	0.47125	106,597
11/14/2012	0.48500	109,707
Total	$1.78375	$403,485
2/14/2013	$0.50000	$113,340
5/15/2013(a)	0.50750	115,040
Total	$1.00750	$228,380

(a) Our general partner's board of directors declared this cash distribution on April 25, 2013 to be paid on May 15, 2013 to unitholders of record at the close of business on May 8, 2013.

12. 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 have made associated with our energy commodity derivatives contracts. The carrying amount reported on our consolidated balance sheets approximates fair value as the deposits change daily in relation to the associated contracts and are held in separate accounts.
- Energy commodity derivatives contracts. These include NYMEX futures and exchange-traded butane futures 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 8 - Derivative Financial Instruments for further disclosures regarding these contracts.
- Long-term receivables. These are primarily insurance receivables, whose 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, 2012 and March 31, 2013. The carrying amount of borrowings, if any, under our revolving credit facility approximates fair value due to the variable rates of that instrument.

The following table reflects the carrying amounts and fair values of our financial instruments as of December 31, 2012 and March 31, 2013 (in thousands):

Assets (Liabilities)	December 31, 2012		March 31, 2013	
	Carrying	Fair	Carrying	Fair

	Amount	Value	Amount	Value
Cash and cash equivalents	$328,278	$328,278	$221,003	$221,003
Energy commodity derivatives deposits	$18,304	$18,304	$14,592	$14,592
Energy commodity derivatives contracts, net	$(7,338)	$(7,338)	$(5,089)	$(5,089)
Long-term receivables	$5,135	$5,108	$4,563	$4,541
Debt	$(2,393,408)	$(2,721,985)	$(2,391,718)	$(2,701,065)

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Fair Value Measurements

The following tables summarize the recurring fair value measurements recorded or disclosed as of December 31, 2012 and March 31, 2013, 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, 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)
Cash equivalents	$319,716	$319,716	$—	$—
Energy commodity derivatives contracts	$(7,338)	$(7,338)	$—	$—
Long-term receivables	$5,108	$—	$—	$5,108
Debt	$(2,721,985)	$(2,721,985)	$—	$—

		Fair Value Measurements as of March 31, 2013 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)
Cash equivalents	$205,526	$205,526	$—	$—
Energy commodity derivatives contracts	$(5,089)	$(5,089)	$—	$—
Long-term receivables	$4,541	$—	$—	$4,541
Debt	$(2,701,065)	$(2,701,065)	$—	$—

13. Related Party Transactions

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 March 31, 2012 and 2013, respectively, we made purchases of petroleum products from subsidiaries of Targa of $12.2 million and $14.2 million. These purchases were made on the same terms as comparable third-party transactions. We had $0.1 million payable to Targa at both December 31, 2012 and March 31, 2013.

See Note 4 – Investments in Non-Controlled Entities for a discussion of affiliate joint venture transactions we account for under the equity method.

14. Subsequent Events

Recognizable events

No recognizable events occurred during the period.

Non-recognizable events

In April 2013, our general partner's board of directors declared a quarterly distribution of $0.5075 per unit to be paid on May 15, 2013 to unitholders of record at the close of business on May 8, 2013. The total cash distributions expected to be paid are $115.0 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 refined petroleum products and crude oil. As of March 31, 2013, our three operating segments included:

- refined products segment, including our 8,800-mile refined products pipeline system with 49 terminals as well as 27 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;
- crude oil segment, comprised of approximately 800 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 15 million barrels; and
- marine storage segment, consisting of marine terminals located along coastal waterways with an aggregate storage capacity of approximately 26 million barrels.

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, (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, 2012, and (iii) updates to the information contained in our Annual Report for the year ended December 31, 2012 related to the changes made in our reporting segments on Form 8-K, which we filed with the Securities and Exchange Commission on April 29, 2013.

Recent Developments

Longhorn Pipeline Reversal Project. In mid-April 2013, we began deliveries of crude oil from our Longhorn pipeline. From the mid-April start date through the end of second quarter 2013, we expect Longhorn's crude oil deliveries to average approximately 90,000 barrels per day and increase to its full capacity of 225,000 barrels per day in the third quarter of 2013.

Pipeline Acquisition. On February 22, 2013, we announced an agreement to acquire approximately 800 miles of refined petroleum products pipeline from Plains All American Pipeline, L.P. for $190 million. We are currently waiting on regulatory approval to complete this transaction. We expect to fund this acquisition with cash on hand and, if necessary, with borrowings under our revolving credit facility.

Cash Distribution. In April 2013, the board of directors of our general partner declared a quarterly cash distribution of $0.5075 per unit for the period of January 1, 2013 through March 31, 2013. This quarterly cash distribution will be paid on May 15, 2013 to unitholders of record on May 8, 2013. Total distributions expected to be paid under this declaration are approximately $115.0 million.

Change in Reporting Segments. During first quarter 2013, we completed a reorganization to our reporting segments to reflect strategic changes in our businesses, particularly in the area of our crude oil activities, which have had or will have a significant impact on the way we manage our operations. Accordingly, we have restated our segment disclosures for all periods included in this report.

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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 table, 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 table. 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 this table. Product margin is a non-GAAP measure; however, its components of product sales and product purchases are determined in accordance with GAAP. Our butane blending, fractionation and other commodity-related activities generate significant product revenues. We believe the product margin from these activities, which takes into account the related product purchases, better represents its importance to our results of operations.

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Three Months Ended March 31, 2012 Compared to Three Months Ended March 31, 2013

	Three Months Ended March 31,		Variance Favorable (Unfavorable)	
	2012	2013	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenues:				
Refined products	$157.7	$165.4	$7.7	5
Crude oil	21.2	23.2	2.0	9
Marine storage	38.7	38.7	—	—
Total transportation and terminals revenues	217.6	227.3	9.7	4
Affiliate management fee revenue	0.2	3.4	3.2	n/a
Operating expenses:				
Refined products	57.2	46.3	10.9	19
Crude oil[(a)]	(0.9)	5.1	(6.0)	n/a
Marine storage	12.9	14.6	(1.7)	(13)
Intersegment eliminations	(0.7)	(0.8)	0.1	14
Total operating expenses	68.5	65.2	3.3	5
Product margin:				
Product sales revenues	275.7	201.7	(74.0)	(27)
Product purchases	248.6	160.4	88.2	35
Product margin[(b)]	27.1	41.3	14.2	52
Earnings of non-controlled entities	1.6	2.1	0.5	31
Operating margin	178.0	208.9	30.9	17
Depreciation and amortization expense	31.5	36.3	(4.8)	(15)
G&A expense	23.7	30.1	(6.4)	(27)
Operating profit	122.8	142.5	19.7	16
Interest expense (net of interest income and interest capitalized)	28.2	28.3	(0.1)	—
Debt placement fee amortization expense	0.5	0.5	—	—
Income before provision for income taxes	94.1	113.7	19.6	21
Provision for income taxes	0.6	0.7	(0.1)	(17)
Net income	$93.5	$113.0	$19.5	21
Operating Statistics:				
Refined products:				
Transportation revenue per barrel shipped	$1.197	$1.136		
Volume shipped (million barrels):				
Gasoline	45.9	53.6		
Distillates	29.8	33.8		
Aviation fuel	5.6	4.5		
Liquefied petroleum gases	1.0	1.1		
Total volume shipped	82.3	93.0		
Crude oil:				
Transportation revenue per barrel shipped	$0.276	$0.313		
Volume shipped (million barrels)	14.9	15.9		
Crude terminal average utilization (million barrels per month)	12.6	12.8		
Marine storage:				

Marine terminal average utilization (million barrels per month)	24.1	22.7

(a) Product overages more than offset other operating expenses for the crude oil segment in first quarter 2012.
(b) Product margin does not include depreciation or amortization expense.

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Transportation and terminals revenues increased $9.7 million resulting from:

- an increase in refined products revenues of $7.7 million primarily due to a 13% increase in transportation volumes, and our mid-2012 tariff increase. Significantly higher gasoline and distillate shipments resulted from stronger demand in the markets we serve, in part due to the seasonal reversal of a portion of our Oklahoma system in 2013, which allowed deliveries south into Texas markets historically served from the Gulf Coast, and an incentive tariff implemented for our South Texas pipeline. The average tariff rate declined between periods as the benefit from the 8.6% tariff increase implemented on July 1, 2012 was more than offset by additional short-haul movements in part due to higher South Texas volumes, which ship at a lower rate than our other pipeline shipments; and
- an increase in crude oil revenues of $2.0 million primarily due to a 7% increase in shipments on our Houston-area crude oil distribution system resulting from deliveries to additional locations that have been connected to our pipeline system and increased deliveries to existing customers as well as higher tariffs.

Affiliate management fee revenue increased $3.2 million due to construction management fees we received in first quarter 2013 related to BridgeTex Pipeline Company, LLC ("BridgeTex") and the management fee we received from operating the storage tanks for Texas Frontera, LLC ("Texas Frontera"), both of which began after first quarter 2012.

Operating expenses decreased $3.3 million resulting from:

- a decrease in refined products expenses of $10.9 million primarily due to higher product overages (which reduce operating expenses) and lower environmental costs in the current period;
- an increase in crude oil expenses of $6.0 million primarily due to lower product overages and higher asset integrity costs; and
- an increase in marine storage expenses of $1.7 million primarily due to insurance reimbursements received in first quarter 2012 for hurricane-related damage.

Product sales revenues primarily resulted from our butane blending activities, product gains from our independent terminals 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 futures 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 futures agreements, which were not designated as hedges, are included as adjustments to product purchases. Product margin increased $14.2 million primarily due to unrealized gains on NYMEX contracts in the current quarter compared to unrealized losses on NYMEX contracts in first quarter 2012. See Other Items—Commodity Derivative Agreements—Product Sales Revenues below for more information about our NYMEX contracts.

Earnings of non-controlled entities increased $0.5 million primarily due to earnings from our 50% interest in Texas Frontera, LLC, which began operations in October 2012.

Depreciation and amortization expense increased $4.8 million primarily due to increased amortization of intangible assets and expansion capital projects placed into service since first quarter 2012.

G&A expense increased $6.4 million primarily due to higher compensation costs resulting from an increase in employee headcount and higher equity-based compensation costs and deferred board of director compensation expense primarily due to a higher price for our limited partner units.

Distributable Cash Flow

Distributable cash flow ("DCF") and adjusted EBITDA are non-GAAP measures. Management uses DCF to evaluate our ability to generate cash for distribution to our limited partners. Management also uses this measure as a basis for recommending to our general partner's board of directors the amount of cash distributions to be paid each period. Adjusted EBITDA is an important measure utilized by the investment community to assess the financial results of an entity. 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 three months ended March 31, 2012 and 2013 to net income, which is its nearest comparable GAAP financial measure, was as follows (in millions):

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	Three Months Ended March 31, 2012	2013	Increase (Decrease)
Net income	$93.5	$113.0	$19.5
Interest expense, net	28.2	28.3	0.1
Depreciation and amortization[1]	32.0	36.9	4.9
Equity-based incentive compensation expense[2]	(10.2)	(7.4)	2.8
Asset retirements and impairments	5.4	1.8	(3.6)
Commodity-related adjustments:			
Derivative (gains) losses recognized in the period associated with future product transactions[3]	13.2	2.3	(10.9)
Derivative losses recognized in previous periods associated with products sold in the period[4]	3.2	(5.2)	(8.4)
Lower-of-cost-or-market adjustments	(1.0)	(2.0)	(1.0)
Houston-to-El Paso cost of sales adjustments[5]	1.0	—	(1.0)
Total commodity-related adjustments	16.4	(4.9)	(21.3)
Other	0.6	(1.4)	(2.0)
Adjusted EBITDA	165.9	166.3	0.4
Interest expense, net	(28.2)	(28.3)	(0.1)
Maintenance capital	(12.0)	(14.1)	(2.1)
Distributable cash flow	$125.7	$123.9	$(1.8)

(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 three months ended March 31, 2012 and 2013 was $2.8 million and $4.9 million, respectively. However, the figures above include an adjustment for minimum statutory tax withholdings we paid in 2012 and 2013 of $13.0 million and $12.3 million, respectively, for equity-based incentive compensation units that vested at 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. We discontinued these commodity activities during 2012 in conjunction with the Longhorn crude pipeline project.

Distributable cash flow decreased by $1.8 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 $89.7 million and $169.8 million for the three months ended March 31, 2012 and 2013, respectively. The $80.1 million increase from 2012 to 2013 was primarily attributable to:

- a $24.3 million increase in net income, excluding the increase in non-cash depreciation and amortization expense;
- a $28.2 million increase resulting from an $11.3 million increase in accounts payable in 2013 versus a $16.9 million decrease in accounts payable in 2012 primarily due to the timing of invoices paid to vendors and suppliers; and

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- a $9.7 million increase resulting from a $1.3 million increase in energy commodity derivatives contracts, net of derivatives deposits in 2013, versus an $8.4 million decrease in 2012 primarily due to the impact of changes in commodity prices on our economic hedges.

Net cash used by investing activities for the three months ended March 31, 2012 and 2013 was $41.9 million and $148.6 million, respectively. During 2013, we spent $89.9 million for capital expenditures, which included $14.1 million for maintenance capital and $75.8 million for expansion capital. Also during 2013, we paid $47.0 million in conjunction with our joint venture capital projects which we account for as investments in non-controlled entities. During 2012, we spent $37.1 million for capital expenditures, which included $12.0 million for maintenance capital and $25.1 million for expansion capital.

Net cash used by financing activities for the three months ended March 31, 2012 and 2013 was $105.9 million and $128.4 million, respectively. During 2013, we paid cash distributions of $113.3 million to our unitholders. Also, in January 2013, the cumulative amounts of the January 2010 equity-based incentive compensation award grants were settled by issuing 476,682 limited partner units and distributing those units to the participants, resulting in payments of associated tax withholdings of $12.3 million. During 2012, we paid cash distributions of $92.2 million to our unitholders. Also, 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, resulting in payments of associated tax withholdings of $13.0 million.

The quarterly distribution amount related to our first-quarter 2013 financial results (to be paid in second quarter 2013) is $0.5075 per unit. If we meet management's targeted distribution growth of 10% for 2013 and the number of outstanding limited partner units remains at 226.7 million, total cash distributions of approximately $470.4 million will be paid to our unitholders related to 2013.

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 or 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 three months ended March 31, 2012 and 2013, our maintenance capital spending was $12.0 million and $14.1 million, respectively. For 2013, we expect to incur maintenance capital expenditures for our existing businesses of approximately $75.0 million.

During the first three months of 2013, we spent $75.8 million for organic growth capital and $47.0 million for capital projects in conjunction with our joint ventures. Based on the progress of expansion projects already underway, including the reversal and conversion of our Longhorn pipeline from refined products to crude oil service and our investment in the BridgeTex pipeline, we expect to spend approximately $900 million for expansion capital during 2013, with an additional $320 million in 2014 to complete our current projects.

Liquidity

Consolidated debt at December 31, 2012 and March 31, 2013 was as follows (in millions):

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	December 31, 2012	March 31, 2013	Weighted-Average Interest Rate at March 31, 2013 (1)
Revolving credit facility	$—	$—	—%
$250.0 million of 6.45% Notes due 2014	249.9	249.9	6.3%
$250.0 million of 5.65% Notes due 2016	251.6	251.5	5.7%
$250.0 million of 6.40% Notes due 2018	261.4	260.9	5.3%
$550.0 million of 6.55% Notes due 2019	575.1	574.2	5.7%
$550.0 million of 4.25% Notes due 2021	558.1	557.9	4.0%
$250.0 million of 6.40% Notes due 2037	249.0	249.0	6.4%
$250.0 million of 4.20% Notes due 2042	248.3	248.4	4.2%
Total debt	$2,393.4	$2,391.8	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, 2012 and March 31, 2013 was $2.4 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 March 31, 2013. Borrowings under this facility may be used for general purposes, including capital expenditures. As of March 31, 2013, there were no borrowings outstanding under this facility; however, $5.6 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.

Off-Balance Sheet Arrangements

None.

Environmental

Our operations are subject to federal, state and local environmental laws and regulations. We have accrued liabilities for estimated costs at our facilities and properties. We record liabilities when environmental costs are probable and can be reasonably estimated. The determination of amounts recorded for environmental liabilities involves significant judgments and assumptions by management. Due to the inherent uncertainties involved in determining environmental liabilities, it is reasonably possible that the actual amounts required to extinguish these liabilities could be materially different from those we have recognized.

Clean Air Act - Section 185 Liability

Section 185 of the Clean Air Act ("CAA 185") requires states to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas that did not meet the attainment deadline. The CAA 185 fees are required annually 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 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 will be subject to the TCEQ's Failure to Attain Rule.

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Management believes the most likely scenario is that we will be assessed fees for excess emissions at our Houston area facilities and our estimate of the possible range of loss associated with this matter is from zero to $14.3 million. As of March 31, 2013, we have accrued $11.1 million as a long-term environmental liability related to this matter. The final Failure to Attain Rule is expected to be published in 2013; therefore, it is likely that our estimate of this loss will change in the near term.

Potential Responsible Party in a Pasadena, Texas Superfund Site

In December 2012, we received a notice from the EPA that we may have potential liability at the U.S. Oil Recovery Superfund Site in Pasadena, Texas as a potential responsible party under Section 107(a) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended. Currently, there is an ongoing removal action designed to stabilize the site, remove the immediate threat posed at the site and set the stage for a later more comprehensive action. Due to the timing of the EPA's notice, we are unable at this point, to reasonably estimate the amount of our potential liability, if any, related to this matter.

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 futures agreements to help manage this commodity price risk. We use NYMEX contracts to hedge against changes in the price of refined 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 futures agreements to economically hedge against changes in the price of butane we expect to purchase in the future as part of our butane blending activity. As of March 31, 2013, our open derivative contracts were as follows:

Open Derivative Contracts Designated as Hedges

- NYMEX contracts covering 0.7 million barrels of crude oil to hedge against future price changes of crude oil linefill and tank bottom inventory. These contracts, which we are accounting for as fair value hedges, mature between April and November 2013. Through March 31, 2013, the cumulative amount of losses from these agreements was $7.1 million. The cumulative losses from these fair value hedges were recorded as adjustments to the asset being hedged, and there has been no ineffectiveness recognized for these hedges. As a result, none of these cumulative losses impacted product sales.

Open Derivative Contracts Not Designated as Hedges

- NYMEX contracts covering 0.9 million barrels of refined products related to our butane blending and fractionation activities. These contracts mature between April and October 2013 and are being accounted for as economic hedges. Through March 31, 2013, the cumulative amount of net unrealized losses associated with these agreements was $1.9 million, of which $0.2 million was recognized in 2012 and $1.7 million was recognized in 2013.

- NYMEX contracts covering 0.5 million barrels of refined products and crude oil related to our pipeline product overages that mature between April and May 2013, which are being accounted for as economic hedges. Through March 31, 2013, the cumulative amount of unrealized losses associated with these agreements was $1.4 million. We recorded these losses as an increase in operating expenses, of which $0.2 million was recognized in 2012 and $1.2 million was recognized in 2013.

- Butane futures agreements to purchase less than 0.1 million barrels of butane that mature April 2013, which are being accounted for as economic hedges. Through March 31, 2013, the cumulative amount of unrealized gains associated with these agreements was less than $0.1 million. We recorded these gains as a decrease in product purchases, of which $0.1 million of net gains was recognized in 2012 and $0.1 million of net losses was recognized in 2013.

Settled Derivative Contracts

- We settled NYMEX contracts covering 2.0 million barrels of refined products related to economic hedges of products from our butane blending and fractionation activities that we sold during first quarter 2013. We recognized a loss of $0.1 million in the current period related to these contracts which we recorded as an adjustment to product sales revenues.

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- We settled NYMEX contracts covering 0.2 million barrels of refined products related to cash flow hedges of products from our butane blending and fractionation activities that we sold during first quarter 2013. We recognized a loss of $4.4 million on the settlement of these contracts which we recorded as an adjustment to product sales revenues.
- We settled NYMEX contracts covering 1.5 million barrels of refined products and crude oil related to economic hedges of product inventories from product overages on our pipeline system which we sold during first quarter 2013. We recognized a loss of $0.7 million on the settlement of these contracts which we recorded as an adjustment to operating expense.
- We settled butane futures agreements covering 0.1 million barrels related to economic hedges of butane purchases we made during first quarter 2013 associated with our butane blending activities. We recognized a loss of $0.7 million on the settlement of these contracts which we recorded as an adjustment to product purchases.

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 months ended March 31, 2012 and 2013 (in millions):

Three Months Ended March 31, 2012	
NYMEX losses recorded during the three months ended March 31, 2012 that were associated with physical product sales during the three months ended March 31, 2012	$(23.8)
NYMEX losses recorded during the three months ended March 31, 2012 that were associated with future physical product sales	(8.2)
Total NYMEX losses that impacted product sales revenues during the three months ended March 31, 2012	$(32.0)

Three Months Ended March 31, 2013	
NYMEX losses recorded during the three months ended March 31, 2013 that were associated with physical product sales during the three months ended March 31, 2013	$(4.5)
NYMEX losses recorded during the three months ended March 31, 2013 that were associated with future physical product sales	(1.7)
Total NYMEX losses that impacted product sales revenues during the three months ended March 31, 2013	$(6.2)

Related Party Transactions. 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 March 31, 2012 and 2013, respectively, we made purchases of petroleum products from subsidiaries of Targa of $12.2 million and $14.2 million. These purchases were made on the same terms as comparable third-party transactions. We had $0.1 million payable to Targa at both December 31, 2012 and March 31, 2013.

We own a 50% interest in Osage Pipe Line Company, LLC ("Osage") and receive a management fee for the operation of its crude oil pipeline. We received management fees from Osage which we reported as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in Texas Frontera, which owns 0.8 million barrels of refined products storage at our Galena Park, Texas terminal. This storage capacity, which began operation in October 2012, is leased to an affiliate of Texas Frontera under a long-term lease agreement. We received management fees from Texas Frontera which we reported as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in BridgeTex, which is in the process of constructing a pipeline and related infrastructure to transport crude oil from Colorado City, Texas for delivery to Houston and Texas City, Texas refineries. This pipeline is expected to begin service in mid-2014. We received construction management fees from BridgeTex which we reported as affiliate management fee revenue on our consolidated statements of income.

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New Accounting Pronouncements

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2013-02, Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. The amendments in ASU 2013-02 do not change the current requirements for reporting net income or other comprehensive income in financial statements. However, the amendments require an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under GAAP that provide additional detail about those amounts. ASU 2013-02 is effective for annual and interim periods beginning after December 15, 2012 and is to be applied prospectively. We adopted this standard in the first quarter of 2013 and its adoption did not have a material impact on our results of operations, financial position or cash flows.

In December 2011, the FASB issued ASU 2011-11, Disclosures about Offsetting Assets and Liabilities. This ASU requires entities that have financial instruments and derivatives that are either: (i) offset in accordance with ASC Topic 210 or Topic 815 or (ii) are subject to an enforceable master netting arrangement or similar agreement to make additional disclosures of the gross and net amounts of those assets and liabilities, the amounts offset in accordance with ASC Topics 210 and 815, as well as qualitative disclosures of the entity's master netting arrangement or similar agreement. In January 2013, the FASB issued ASU 2013-01, Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities. The amendments in ASU 2013-01 clarify that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with ASC Topic 815, Derivatives and Hedging. ASU 2011-11 must be applied retrospectively and became effective for fiscal years beginning on or after January 1, 2013. We adopted these standards in the first quarter of 2013 and their adoption did not have a material impact on our results of operations, financial position or cash flows.

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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 physical contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting. As of March 31, 2013, we had commitments under forward purchase and sale contracts used in our butane blending and fractionation activities as follows (in millions):

	Value	Barrels
Forward purchase contracts	$7.8	0.1
Forward sale contracts	$29.9	0.3

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 futures agreements to hedge against changes in the price of butane that we expect to purchase in future periods. At March 31, 2013, we had open NYMEX contracts representing 2.1 million barrels of petroleum products we expect to sell in the future. Additionally, we had open butane futures agreements for less than 0.1 million barrels of butane we expect to purchase in the future.

At March 31, 2013, the fair value of our open NYMEX contracts was a net liability of $5.1 million and the fair value of our butane futures agreements was an asset of less than $0.1 million. Combined, the net liability of $5.1 million was recorded as a current liability to energy commodity derivatives contracts.

At March 31, 2013, open NYMEX contracts representing 1.4 million barrels of petroleum products did not qualify for hedge accounting treatment. A $10.00 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 $14.0 million decrease in our operating profit and a $10.00 per barrel decrease in the price of these NYMEX contracts for RBOB or heating oil would result in a $14.0 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.

Interest Rate Risk

At March 31, 2013, 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.

During 2012 we terminated and settled certain interest rate swap agreements and realized a gain of $11.0 million, which was recorded to other comprehensive income. The purpose of these swaps was to hedge against the variability of future interest payments on the refinancing of our debt that matures in 2014. If management were to determine that it was probable this forecasted transaction would not occur in 2014, the $11.0 million gain we have recorded to other comprehensive loss would be reclassified into earnings.

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

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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 March 31, 2013 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 products, crude oil, liquefied petroleum gases and ammonia in the U.S.;
- price fluctuations for refined products, crude oil, liquefied petroleum gases 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 co-owners 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, refinance our existing obligations when due and maintain adequate liquidity;
- development of alternative energy sources, including but not limited to natural gas, 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 refined products or crude oil pipelines owned and operated by third parties and connected to our assets;
- changes in demand for storage in our refined products or crude oil 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;
- shut-downs or cutbacks at refineries, oil wells, 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 accretive acquisitions and joint ventures and successfully execute our business strategy;
- uncertainty of estimates, including accruals and costs of environmental remediation;
- our ability to cooperate with and rely on our joint venture co-owners;

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- 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, labor, supplies and rights-of-way required for construction of our growth projects, and to complete construction without significant delays, disputes or cost overruns;
- 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 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 or our customers 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 and laws and regulations affecting hydraulic fracturing;
- 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 repercussions from terrorist activities, including cyber attacks, and the government's response thereto; and
- other factors and uncertainties inherent in the transportation, storage and distribution of refined products and crude oil.

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 February 2010, a class action lawsuit was filed against us, ARCO Midcon L.L.C. and WilTel Communications, L.L.C. ("WilTel"). The complaint alleges that the property owned by plaintiffs and those similarly situated has been damaged by the existence of hazardous chemicals migrating from a pipeline easement onto the plaintiffs' property. We acquired the pipeline from ARCO Pipeline ("APL") in 1994 as part of a larger transaction and subsequently transferred the property to WilTel. We are required to indemnify and defend WilTel pursuant to the transfer agreement. Prior to the acquisition of the pipeline from APL, the pipeline was purged of product. Neither we nor WilTel ever transported hazardous materials through the pipeline. A hearing on the plaintiff's Motion for Class Certification was held in the U.S. District Court for the Eastern District of Missouri in December 2012. The court has not yet rendered a decision on the issue of class certification. 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 July 2011, we received an information request from the 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 December 2012, we received a notice from the EPA that we may have potential liability at the U.S. Oil Recovery Superfund Site in Pasadena, Texas as a potential responsible party under Section 107(a) of the CERCLA Act of 1980. Currently, there is an ongoing removal action designed to stabilize the site, remove the immediate threat posed at the site and set the stage for a later more comprehensive action. Due to the timing of the EPA's notice, we are unable at this point, to reasonably estimate the amount of our potential liability, if any, related to this matter.

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, 2012, 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.

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

Our butane blending activities subject us to federal regulations that govern renewable fuel requirements in the United States.

The Energy Independence and Security Act of 2007 expanded the required use of renewable fuels in the United States. Each year, the EPA establishes a Renewable Volume Obligation ("RVO") requirement for refiners and fuel manufacturers based

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on overall quotas established by the federal government. By virtue of our butane blending activity, and resulting gasoline production, we are an obligated party and receive an annual RVO from the EPA. In lieu of blending renewable fuels (such as ethanol and bio-diesel), we have the option to purchase renewable energy credits, called RINs, to meet this obligation. RINs are generated when a gallon of biofuel such as ethanol or biodiesel is produced. RINs may be separated when the biofuel is blended into gasoline or diesel, at which point the RIN is available for use in compliance or is available for sale on the open market. The cost of RINs has increased substantially during 2013 and the cost and availability of RINs could have an adverse impact on our results of operations, cash flows and cash distributions.

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.

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 May 3, 2013.

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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