MAGELLAN MIDSTREAM PARTNERS LP
Form 10-Q
October 31, 2014

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

FORM 10-Q

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

For the quarterly period ended September 30, 2014

OR

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

For the transition period from to

Commission File No.: 1-16335

Magellan Midstream Partners, L.P.
(Exact name of registrant as specified in its charter)

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

One Williams Center, P.O. Box 22186, Tulsa, Oklahoma 74121-2186
(Address of principal executive offices and zip code)
(918) 574-7000
(Registrant’s telephone number, including area code)

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

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

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

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

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

As of October 30, 2014, there were 227,068,257 outstanding limited partner units of Magellan Midstream Partners, L.P. that trade on the New York Stock Exchange under the ticker symbol "MMP."

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PART I
FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2013		2014		2013		2014	
Transportation and terminals revenue	$295,326		$360,517		$805,059		$1,031,722	
Product sales revenue	144,852		155,865		504,485		589,585	
Affiliate management fee revenue	3,657		5,219		10,624		15,346	
Total revenue	443,835		521,601		1,320,168		1,636,653	
Costs and expenses:								
Operating	103,262		132,387		245,858		330,758	
Cost of product sales	120,299		91,591		396,025		398,734	
Depreciation and amortization	35,270		38,054		105,788		122,462	
General and administrative	32,755		35,377		96,073		109,621	
Total costs and expenses	291,586		297,409		843,744		961,575	
Earnings of non-controlled entities	2,375		1,645		5,162		4,066	
Operating profit	154,624		225,837		481,586		679,144	
Interest expense	31,852		34,993		95,295		108,674	
Interest income	(215	)	(374	)	(250	)	(1,171	)
Interest capitalized	(3,780	)	(9,205	)	(10,474	)	(21,358	)
Debt placement fee amortization expense	540		566		1,620		1,767	
Income before provision for income taxes	126,227		199,857		395,395		591,232	
Provision for income taxes	604		1,237		3,165		3,798	
Net income	$125,623		$198,620		$392,230		$587,434	
Basic net income per limited partner unit	$0.55		$0.87		$1.73		$2.59	
Diluted net income per limited partner unit	$0.55	0.85	$0.87	2.57	$1.73	0.85	$2.58	
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	226,866		227,294		226,812		227,242	
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	226,866	227,826	227,830	227,421	226,812	227,826	227,422	

See notes to consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2014	2013	2014
Net income	$125,623	$198,620	$392,230	$587,434
Other comprehensive income:				
Derivative activity:				
Net loss on cash flow hedges(1)	(36)	(1,830)	(4,596)	(5,443)
Reclassification of net loss (gain) on cash flow hedges to income(1)	(41)	119	4,285	(60)
Changes in employee benefit plan assets and benefit obligations recognized in other comprehensive income:				
Net actuarial loss	(367)	—	(367)	—
Amortization of prior service credit(2)	(852)	(928)	(2,554)	(2,751)
Amortization of actuarial loss(2)	1,343	985	4,027	3,001
Settlement cost(2)	—	30	—	1,599
Total other comprehensive income (loss)	47	(1,624)	795	(3,654)
Comprehensive income	$125,670	$196,996	$393,025	$583,780

(1) See Note 9–Derivative Financial Instruments for details of the amount of gain/loss recognized in accumulated other comprehensive loss ("AOCL") on derivatives and the amount of gain/loss reclassified from AOCL into income.
(2) These AOCL components are included in the computation of net periodic pension cost (see Note 7–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, 2013	September 30, 2014 (Unaudited)
ASSETS		
Current assets:		
Cash and cash equivalents	$25,235	$14,853
Trade accounts receivable	116,295	106,495
Other accounts receivable	6,462	11,160
Inventory	187,224	202,475
Energy commodity derivatives contracts, net	—	27,757
Energy commodity derivatives deposits	14,782	133
Other current assets	46,735	39,107
Total current assets	396,733	401,980
Property, plant and equipment	4,986,750	5,174,107
Less: Accumulated depreciation	1,070,492	1,182,361
Net property, plant and equipment	3,916,258	3,991,746
Investments in non-controlled entities	360,852	736,172
Long-term receivables	2,730	29,815
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of $8,809 and $10,847 at December 31, 2013 and September 30, 2014, respectively)	7,290	5,252
Debt placement costs (less accumulated amortization of $9,113 and $8,386 at December 31, 2013 and September 30, 2014, respectively)	17,505	18,650
Tank bottom inventory	61,915	64,221
Other noncurrent assets	4,269	10,300
Total assets	$4,820,812	$5,311,396
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$76,326	$84,636
Accrued payroll and benefits	42,243	41,574
Accrued interest payable	44,935	44,361
Accrued taxes other than income	38,574	45,170
Environmental liabilities	12,147	12,209
Deferred revenue	63,164	70,648
Accrued product purchases	63,033	54,449
Energy commodity derivatives contracts, net	6,737	—
Current portion of long-term debt	249,971	—
Other current liabilities	41,146	40,606
Total current liabilities	638,276	393,653
Long-term debt	2,435,316	3,003,707
Long-term pension and benefits	51,637	41,133
Other noncurrent liabilities	21,802	29,443
Environmental liabilities	26,339	25,105
Commitments and contingencies		
Partners’ capital:		

Limited partner unitholders (226,679 units and 227,068 units outstanding at December 31, 2013 and September 30, 2014, respectively)	1,666,946	1,841,513
Accumulated other comprehensive loss	(19,504)	(23,158)
Total partners' capital	1,647,442	1,818,355
Total liabilities and partners' capital	$4,820,812	$5,311,396

See notes to consolidated financial statements.

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

	Nine Months Ended September 30, 2013	2014
Operating Activities:		
Net income	$392,230	$587,434
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense	105,788	122,462
Debt placement fee amortization expense	1,620	1,767
Loss on sale and retirement of assets	4,269	4,830
Earnings of non-controlled entities	(5,162)	(4,066)
Distributions from investments in non-controlled entities	1,907	2,398
Equity-based incentive compensation expense	14,499	17,731
Changes in employee benefit plan assets and benefit obligations	1,473	1,849
Changes in operating assets and liabilities:		
Trade accounts receivable and other accounts receivable	(11,094)	10,929
Inventory	13,403	(15,251)
Energy commodity derivatives contracts, net of derivatives deposits	(8,887)	(17,540)
Accounts payable	956	6,483
Accrued payroll and benefits	5,782	(669)
Accrued interest payable	(4,885)	(574)
Accrued taxes other than income	5,306	6,596
Accrued product purchases	(2,347)	(8,584)
Deferred revenue	21,511	7,484
Current and noncurrent environmental liabilities	(10,767)	(1,172)
Other current and noncurrent assets and liabilities	590	(8,792)
Net cash provided by operating activities	526,192	713,315
Investing Activities:		
Property, plant and equipment:		
Additions to property, plant and equipment	(289,669)	(237,240)
Proceeds from sale and disposition of assets	2,414	264
Increase (decrease) in accounts payable related to capital expenditures	(29,768)	2,477
Acquisition of business	(57,000)	—
Acquisition of assets	(22,500)	—
Investments in non-controlled entities	(181,377)	(378,220)
Distributions in excess of earnings of non-controlled entities	604	3,918
Net cash used by investing activities	(577,296)	(608,801)
Financing Activities:		
Distributions paid	(349,087)	(417,238)
Net commercial paper borrowings	—	315,967
Net borrowings under revolver	98,400	—
Borrowings under long-term notes	—	257,713
Payments on notes	—	(250,000)
Debt placement costs	—	(2,912)
Net payment on financial derivatives	—	(3,613)

Settlement of tax withholdings on long-term incentive compensation	(12,259)	(14,813)
Net cash used by financing activities	(262,946)	(114,896)
Change in cash and cash equivalents	(314,050)	(10,382)
Cash and cash equivalents at beginning of period	328,278	25,235
Cash and cash equivalents at end of period	$14,228	$14,853
Supplemental non-cash investing and financing activities:		
Issuance of limited partner units in settlement of equity-based incentive plan awards	$6,404	$7,315

See notes to consolidated financial statements.

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

1. Organization, Description of Business 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.

Description of Business

We are principally engaged in the transportation, storage and distribution of refined petroleum products and crude oil. As of September 30, 2014, our asset portfolio, including the assets of our joint ventures, consisted of:

- our refined products segment, including our 9,500-mile refined products pipeline system with 54 terminals as well as 27 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

- our crude oil segment, comprised of approximately 1,600 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 20 million barrels, of which 12 million barrels is used for leased storage. BridgeTex Pipeline Company, LLC ("BridgeTex") began commercial service in September 2014 and is now included in the pipeline miles and storage capacity amounts of our crude oil segment; and

- our marine storage segment, consisting of five marine terminals located along coastal waterways with an aggregate storage capacity of approximately 27 million barrels.

Products transported, stored and distributed through our pipelines and terminals include:

- refined products, which are the output from refineries and are primarily used as fuels by consumers. Refined products include gasoline, diesel fuel, aviation fuel, kerosene and heating oil. Collectively, diesel fuel and heating oil are referred to as distillates;

- liquefied petroleum gases, or LPGs, which are produced as by-products of the crude oil refining process and in connection with natural gas production. LPGs include butane and propane;

- blendstocks, which are blended with refined products to change or enhance their characteristics such as increasing a gasoline's octane or oxygen content. Blendstocks include alkylates, oxygenates and natural gasoline;

- heavy oils and feedstocks, which are used as burner fuels or feedstocks for further processing by refineries and petrochemical facilities. Heavy oils and feedstocks include No. 6 fuel oil and vacuum gas oil;

- crude oil and condensate, which are used as feedstocks by refineries and petrochemical facilities;

- biofuels, such as ethanol and biodiesel, which are increasingly required by government mandates; and

- ammonia, which is primarily used as a nitrogen fertilizer.

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

Except for ammonia, we use the term petroleum products to describe any, or a combination, of the above-noted products.

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, 2013 which is derived from our audited financial statements, include all normal and recurring adjustments necessary to present fairly our financial position as of September 30, 2014, the results of operations for the three and nine months ended September 30, 2013 and 2014 and cash flows for the nine months ended September 30, 2013 and 2014. The results of operations for the nine months ended September 30, 2014 are not necessarily indicative of the results to be expected for the full year ending December 31, 2014 as profits from our blending activities are realized mostly during the first and fourth quarters of each year. Additionally, gasoline demand, which drives transportation volumes and revenues on our pipeline systems, generally trends higher during the summer driving months.

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, 2013.

2. Product Sales Revenue

The amounts reported as product sales revenue on our consolidated statements of income include revenue 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 in which we acquire or produce petroleum products. Some of these NYMEX contracts could qualify for hedge accounting treatment, and when the contracts are so designated we 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 9 – 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 and nine months ended September 30, 2013 and 2014, product sales revenue included the following (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2014	2013	2014
Physical sale of petroleum products	$146,887	$108,320	$500,347	$555,870
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)	(2,035)	47,546	4,149	33,703
Other	—	(1)	(11)	12
Total NYMEX contract adjustments	(2,035)	47,545	4,138	33,715
Total product sales revenue	$144,852	$155,865	$504,485	$589,585

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

3. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. Our segments are managed separately because each segment requires different marketing strategies and business knowledge. Management evaluates performance based on segment operating margin, which includes revenue from affiliates and external customers, operating expenses, cost of product sales 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 consider when evaluating the core profitability of our separate operating segments.

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

	Three Months Ended September 30, 2013 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	$205,859	$49,519	$39,948	$—	$295,326
Product sales revenue	143,549	—	1,303	—	144,852
Affiliate management fee revenue	—	3,369	288	—	3,657
Total revenue	349,408	52,888	41,539	—	443,835
Operating expenses	82,174	4,034	17,813	(759)	103,262
Cost of product sales	120,429	—	(130)	—	120,299
Earnings of non-controlled entities	—	(1,770)	(605)	—	(2,375)
Operating margin	146,805	50,624	24,461	759	222,649
Depreciation and amortization expense	21,851	5,538	7,122	759	35,270
G&A expenses	22,741	5,100	4,914	—	32,755
Operating profit	$102,213	$39,986	$12,425	$—	$154,624

	Three Months Ended September 30, 2014 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	$237,972	$78,839	$43,706	$—	$360,517
Product sales revenue	155,134	—	731	—	155,865
Affiliate management fee revenue	—	4,902	317	—	5,219
Total revenue	393,106	83,741	44,754	—	521,601
Operating expenses	101,206	14,375	17,691	(885)	132,387
Cost of product sales	91,407	—	184	—	91,591
Earnings of non-controlled entities	—	(959)	(686)	—	(1,645)
Operating margin	200,493	70,325	27,565	885	299,268
Depreciation and amortization expense	23,050	6,918	7,201	885	38,054
G&A expenses	22,600	7,635	5,142	—	35,377
Operating profit	$154,843	$55,772	$15,222	$—	$225,837

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

	Nine Months Ended September 30, 2013 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	$573,615	$113,905	$117,539	$—	$805,059
Product sales revenue	499,285	—	5,200	—	504,485
Affiliate management fee revenue	—	9,767	857	—	10,624
Total revenue	1,072,900	123,672	123,596	—	1,320,168
Operating expenses	194,911	13,168	40,060	(2,281)	245,858
Cost of product sales	393,187	—	2,838	—	396,025
Earnings of non-controlled entities	—	(3,255)	(1,907)	—	(5,162)
Operating margin	484,802	113,759	82,605	2,281	683,447
Depreciation and amortization expense	64,428	18,111	20,968	2,281	105,788
G&A expenses	67,235	14,142	14,696	—	96,073
Operating profit	$353,139	$81,506	$46,941	$—	$481,586

	Nine Months Ended September 30, 2014 (in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	$680,697	$226,298	$124,727	$—	$1,031,722
Product sales revenue	585,178	—	4,407	—	589,585
Affiliate management fee revenue	—	14,399	947	—	15,346
Total revenue	1,265,875	240,697	130,081	—	1,636,653
Operating expenses	249,665	35,300	48,321	(2,528)	330,758
Cost of product sales	397,980	—	754	—	398,734
Earnings of non-controlled entities	—	(1,667)	(2,399)	—	(4,066)
Operating margin	618,230	207,064	83,405	2,528	911,227
Depreciation and amortization expense	78,305	20,106	21,523	2,528	122,462
G&A expenses	70,993	21,326	17,302	—	109,621
Operating profit	$468,932	$165,632	$44,580	$—	$679,144
	As of September 30, 2014				
Segment assets	$2,849,397	$1,732,464	$638,948	$—	$5,220,809
Corporate assets					90,587
Total assets					$5,311,396

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4. Investments in Non-Controlled Entities

We own a 50% interest in Texas Frontera, LLC ("Texas Frontera"), which owns approximately one million barrels of refined products storage at our Galena Park, Texas terminal. The storage capacity owned by this joint venture is leased to an affiliate of Texas Frontera under a long-term lease agreement. We receive management fees from Texas Frontera, which we report as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in Osage Pipe Line Company, LLC ("Osage"), which owns a 135-mile crude oil pipeline in Oklahoma and Kansas that we operate. We receive management fees from Osage, which we report as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in Double Eagle Pipeline LLC ("Double Eagle"), which transports condensate from the Eagle Ford shale formation in South Texas via a 195-mile pipeline to our terminal in Corpus Christi, Texas. Double Eagle is operated by an affiliate of the other 50% member of Double Eagle. In addition to our equity ownership in Double Eagle, we receive throughput revenue from Double Eagle that is included in our transportation and terminals revenue on our consolidated statements of income. For the three months ended September 30, 2013 and 2014, we received throughput revenue of $0.5 million and $0.7 million, respectively. For the nine months ended September 30, 2013 and 2014, we received throughput revenue of $0.8 million and $2.0 million, respectively. We recognized a $0.2 million and $0.3 million trade accounts receivable from Double Eagle at December 31, 2013 and September 30, 2014, respectively.

We own a 50% interest in BridgeTex, which owns a 450-mile pipeline with related infrastructure to transport crude oil from Colorado City, Texas for delivery to the Houston Gulf Coast area. BridgeTex began commercial service to the Houston Gulf Coast region during September 2014. We receive management fees from BridgeTex, which we report as affiliate management fee revenue on our consolidated statements of income.

We received $4.8 million from BridgeTex in 2013 as a deposit for the purchase of emission reduction credits, which were necessary for the operation of BridgeTex's tanks in East Houston, Texas. In second quarter 2014, we transferred these emission reduction credits to BridgeTex and recorded $2.4 million as a reduction of operating expense. We recorded the remaining $2.4 million as an adjustment to our investment in BridgeTex, which we are amortizing to earnings of non-controlled entities over the weighted average depreciable lives of the BridgeTex assets. Also during 2013, we received $1.4 million from BridgeTex for the purchase of easement rights from us, of which $0.7 million was recorded as a reduction of operating expense and $0.7 million was recorded as an adjustment to our investment in BridgeTex, which we are amortizing to earnings of non-controlled entities over the weighted average depreciable lives of the BridgeTex assets.

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 as earnings of non-controlled entities.

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

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

	BridgeTex	All Others	Consolidated
Investments at December 31, 2013	$246,875	$113,977	$360,852
Additional investment	368,869	9,351	378,220
Other adjustment to investment	—	(650)	(650)
Earnings of non-controlled entities:			
Proportionate share of earnings	9	4,620	4,629
Amortization of excess investment and capitalized interest	—	(563)	(563)
Earnings of non-controlled entities	9	4,057	4,066
Less:			
Distributions of earnings from investments in non-controlled entities	—	2,398	2,398
Distributions in excess of earnings of non-controlled entities	—	3,918	3,918
Investments at September 30, 2014	$615,753	$120,419	$736,172

Summarized financial information of our non-controlled entities as of and for the nine months ended September 30, 2014 follows (in thousands):

	BridgeTex	All Others	Consolidated
Current assets	$67,027	$19,419	$86,446
Noncurrent assets	1,043,761	198,027	1,241,788
Total assets	$1,110,788	$217,446	$1,328,234
Current liabilities	99,808	10,739	110,547
Noncurrent liabilities	—	99	99
Total liabilities	$99,808	$10,838	$110,646
Equity	$1,010,980	$206,608	$1,217,588
Revenue	$428	$27,346	$27,774
Net income	$17	$9,241	$9,258

5. Business Combinations

During 2013, we acquired certain refined petroleum products pipelines and terminals from Plains All American Pipeline, L.P. We have accounted for this acquisition as a business combination under the acquisition method of accounting in accordance with Accounting Standards Codification ("ASC") 805, Business Combinations. The acquisition was completed in two parts, as follows:

- New Mexico/Texas System. In July 2013, we acquired approximately 250 miles of common carrier pipeline that transports refined petroleum products from El Paso, Texas north to Albuquerque, New Mexico and

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

transports products south to the United States–Mexico border for delivery within Mexico via a third-party pipeline for $57.0 million. We funded this acquisition with cash on hand.

- Rocky Mountain System. In November 2013, we acquired approximately 550 miles of common carrier pipeline that distributes refined petroleum products in Colorado, South Dakota and Wyoming for $135.0 million. The system includes four terminals with nearly 1.7 million barrels of storage. We funded this acquisition primarily with proceeds from our $300.0 million debt offering we completed in October 2013.

We completed our valuation process of this 2013 business combination during the second quarter of 2014, and there were no changes to our preliminary purchase price allocation amounts since December 31, 2013 (as reported in our 2013 annual report on Form 10-K).

6. Inventory

Inventory at December 31, 2013 and September 30, 2014 was as follows (in thousands):

	December 31, 2013	September 30, 2014
Refined products	$77,144	$32,206
Liquefied petroleum gases	23,476	75,600
Transmix	72,156	77,344
Crude oil	7,188	11,718
Additives	7,260	5,607
Total inventory	$187,224	$202,475

7. 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 and nine months ended September 30, 2013 and 2014 (in thousands):

	Three Months Ended September 30, 2013		Three Months Ended September 30, 2014	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of net periodic benefit costs:				
Service cost	$3,476	$72	$3,348	$57
Interest cost	1,342	103	1,332	126

Expected return on plan assets	(1,556)	—	(1,588)	—
Amortization of prior service cost (credit)[1]	76	(928)	—	(928)
Amortization of actuarial loss[1]	1,084	259	756	229
Settlement cost[1]	—	—	30	—
Net periodic benefit cost (credit)	$4,422	$(494)	$3,878	$(516)

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

	Nine Months Ended September 30, 2013		Nine Months Ended September 30, 2014	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Components of net periodic benefit costs:				
Service cost	$10,426	$216	$10,052	$171
Interest cost	4,026	309	5,021	379
Expected return on plan assets	(4,671)	—	(4,775)	—
Amortization of prior service cost (credit)(1)	230	(2,784)	33	(2,784)
Amortization of actuarial loss(1)	3,251	776	2,315	686
Settlement cost(1)	—	—	1,599	—
Net periodic benefit cost (credit)	$13,262	$(1,483)	$14,245	$(1,548)

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

Contributions estimated to be paid into the plans in 2014 are $21.1 million and $0.7 million for the pension and postretirement benefit plans, respectively.

8. Debt

Consolidated debt at December 31, 2013 and September 30, 2014 was as follows (in thousands, except as otherwise noted):

	December 31, 2013	September 30, 2014	Weighted-Average Interest Rate for Nine Months Ending September 30, 2014 (1)
Commercial paper(2)	$—	$315,967	0.3%
Revolving credit facility(2)	—	—	1.3%
$250.0 million of 6.45% Notes due 2014(2)	249,971	—	6.3%
$250.0 million of 5.65% Notes due 2016	251,183	250,864	5.7%
$250.0 million of 6.40% Notes due 2018	259,346	257,796	5.4%
$550.0 million of 6.55% Notes due 2019	571,515	568,789	5.7%
$550.0 million of 4.25% Notes due 2021	557,213	556,535	4.0%
$250.0 million of 6.40% Notes due 2037	248,998	249,012	6.4%
$250.0 million of 4.20% Notes due 2042	248,377	248,399	4.2%
	298,684	556,345	5.1%

$550.0 million ($300.0 million at December 31, 2013) of 5.15% Notes due 2043[(2)]			
Total debt	$2,685,287	$3,003,707	5.0%

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

(2) These borrowings were outstanding for only a portion of the nine month period ending September 30, 2014. The weighted-average interest rate for these borrowings was calculated based on the number of days the borrowings were outstanding during the noted period.

All of the instruments detailed in the table above are senior indebtedness.

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

The face value of our debt at December 31, 2013 and September 30, 2014 was $2.7 billion and $3.0 billion, respectively. The difference between the face value and carrying value of the debt outstanding is the unamortized portion of 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.

2014 Debt Offering

In March 2014, we issued $250.0 million of our 5.15% notes due October 15, 2043 in an underwritten public offering. The notes were issued at 103.1% of par. We used the net proceeds from this offering of approximately $255.0 million, after underwriting discounts and offering expenses of $2.7 million, to repay borrowings outstanding under our revolving credit facility and for general partnership purposes, including expansion capital.

Other Debt

Revolving Credit Facility. The total borrowing capacity under our revolving credit facility, which matures in November 2018, is $1.0 billion. Borrowings outstanding under the facility are classified as long-term debt on our consolidated balance sheets. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 1.0% to 1.75% based on our credit ratings. Additionally, an unused commitment fee is assessed at a rate from 0.10% to 0.28%, depending on our credit ratings. The unused commitment fee was 0.125% at September 30, 2014. Borrowings under this facility may be used for general partnership purposes, including capital expenditures. As of September 30, 2014, there were no borrowings outstanding under this facility and $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.

Commercial Paper Program. In April 2014, we initiated a commercial paper program. The maturities of the commercial paper notes vary, but may not exceed 397 days from the date of issuance. The commercial paper notes are sold under customary terms in the commercial paper market and are issued at a discount from par, or alternatively, are sold at par and bear varying interest rates on a fixed or floating basis. The commercial paper we can issue is limited by the amounts available under our revolving credit facility up to an aggregate principal amount of $1.0 billion. We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis; therefore, we have elected to classify our commercial paper borrowings outstanding as long-term debt on our consolidated balance sheets. In second quarter 2014, proceeds from commercial paper borrowings were used in part to repay our $250.0 million of 6.45% senior notes that were due June 1, 2014. Additional commercial paper borrowings have been used for general partnership purposes, including expansion capital.

9. Derivative Financial Instruments

Interest Rate Derivatives

We periodically enter into interest rate derivatives to economically hedge debt, interest or expected debt issuances, and we have historically designated these derivatives as cash flow or fair value hedges for accounting purposes. Adjustments resulting from discontinued hedges continue to be recognized in accordance with their historic hedging relationships.

In third quarter 2014, we entered into $200.0 million of forward-starting interest rate swap agreements to hedge against the risk of variability of future interest payments on a portion of debt we anticipate issuing in the next year. The fair value of these contracts at September 30, 2014 was a net liability of $1.8 million. We account for these agreements as cash flow hedges.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In first quarter 2014, we entered into $200.0 million of interest rate swap agreements to hedge against the variability of future interest payments on an anticipated debt issuance. We accounted for these agreements as cash flow hedges. When we issued $250.0 million of 5.15% notes due 2043 later in the first quarter of 2014, we settled the associated interest rate swap agreements for a loss of $3.6 million. The loss was recorded to other comprehensive income and is being recognized into earnings as an adjustment to our periodic interest expense accruals over the life of the associated notes. This loss was also reported as net payment on financial derivatives in the financing activities of our consolidated statements of cash flows.

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 as a deferred cash flow hedging gain. The purpose of these swaps was to hedge against the variability of future interest payments on the refinancing of our debt that matured in June 2014. We recognized ineffectiveness in earnings on this deferred hedging gain of $0.2 million for the nine months ended September 30, 2014 due to timing of our debt refinancing.

Commodity Derivatives

Hedging Strategies

Our butane blending activities produce gasoline products, and we can reasonably estimate the timing and quantities of sales of these products. We use a combination of forward purchase and sale contracts, NYMEX contracts and Chicago Mercantile Exchange ("CME") butane futures agreements to help manage commodity 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 September 30, 2014, we had commitments under these forward purchase and sale contracts as follows (in millions):

	Notional Value	Barrels
Forward purchase contracts	$248.1	4.2
Forward sale contracts	$80.6	0.9

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 hedge categories:

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Hedge Category	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 is 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 is 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 under ASC 815, Derivatives and Hedging.	Changes in the fair value of these agreements are recognized currently in earnings.

Period changes in the fair value of NYMEX agreements that are accounted for as economic hedges, other than those economic hedges of our pipeline product overages (see discussion of these below), the effective portion of changes in the fair value of cash flow hedges that are reclassified from accumulated other comprehensive income/loss and any ineffectiveness associated with hedges related to our commodity activities are recognized currently in earnings as adjustments to product sales.

We also use CME-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. Period changes in the fair value of these agreements are recognized currently in earnings as adjustments to cost of product sales.

Additionally, we currently hold petroleum product inventories that we obtained from overages on our pipeline systems. We use NYMEX contracts that are not designated as hedges for accounting purposes to help manage price changes related to these overage inventory barrels. Period 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 CME butane futures agreements at September 30, 2014 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 October 2014 and November 2016

NYMEX - Economic Hedges(1)	4.0 million barrels of refined products and crude oil	Between October 2014 and October 2015
CME Butane Futures Agreements - Economic Hedges	0.9 million barrels of butane	Between October 2014 and April 2015

(1) Of the 4.0 million barrels of products we have economically hedged at September 30, 2014, we had open agreements which swap the pricing on 0.8 million of those barrels from New York harbor to Platts Group 3 or Platts Gulf Coast, which are the geographic locations where these barrels will be sold.

Energy Commodity Derivatives Contracts and Deposits Offsets

At September 30, 2014, we had made margin deposits of $0.1 million related to our NYMEX and CME 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

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CME 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 CME 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 CME 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, 2013 and September 30, 2014 (in thousands):

	December 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[(1)]	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheet	Net Asset Amount
Energy commodity derivatives	$(7,167)	$2,665	$(4,502)	$14,782	$10,280

	September 30, 2014				
Description	Gross Amounts of Recognized Assets	Gross Amounts of Liabilities Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet[(2)]	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheet	Net Asset Amount
Energy commodity derivatives	$31,909	$(4,222)	$27,687	$133	$27,820

(1) Net amount includes energy commodity derivative contracts classified as current liabilities, net, of $6,737 and noncurrent assets of $2,235.
(2) Net amount includes energy commodity derivative contracts classified as current assets, net, of $27,757 and noncurrent liabilities of $70.

Impact of Derivatives on Income Statement, Balance Sheet, Cash Flows and AOCL

The changes in derivative activity included in AOCL for the three and nine months ended September 30, 2013 and 2014 were as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
Derivative Gains (Losses) Included in AOCL	2013	2014	2013	2014

Beginning balance	$13,892	$9,835	$14,126	$13,627
Net loss on cash flow hedges	(36)	(1,830)	(4,596)	(5,443)
Reclassification of net loss (gain) on cash flow hedges to income	(41)	119	4,285	(60)
Ending balance	$13,815	$8,124	$13,815	$8,124

During 2014, 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 inventories. Because there was no ineffectiveness recognized on these hedges, the cumulative losses of $11.0 million from the agreements as of September 30, 2014 were fully offset by a cumulative increase of $11.2 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 our results of operations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following tables provide a summary of the effect on our consolidated statements of income for the three and nine months ended September 30, 2013 and 2014 of derivatives accounted for under ASC 815-30, Derivatives and Hedging—Cash Flow Hedges, that were designated as hedging instruments (in thousands):

	Three Months Ended September 30, 2013			
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Gain Reclassified from AOCL into Income	Amount of Gain Reclassified from AOCL into Income Effective Portion	Ineffective Portion
Interest rate contracts	$(36)	Interest expense	$41	$—

	Three Months Ended September 30, 2014			
Derivative Instrument	Amount of Loss Recognized in AOCL on Derivative	Location of Loss Reclassified from AOCL into Income	Amount of Loss Reclassified from AOCL into Income Effective Portion	Ineffective Portion
Interest rate contracts	$(1,830)	Interest expense	$(119)	$—

	Nine Months Ended September 30, 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 Effective Portion	Ineffective Portion
Interest rate contracts	$(36)	Interest expense	$123	$—
NYMEX commodity contracts	(4,560)	Product sales revenue	(4,408)	—
Total cash flow hedges	$(4,596)	Total	$(4,285)	$—

	Nine Months Ended September 30, 2014			
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 Effective Portion	Ineffective Portion
Interest rate contracts	$(5,443)	Interest expense	$(123)	$183

As of September 30, 2014, the net loss estimated to be classified to interest expense over the next twelve months from AOCL is approximately $0.2 million.
The following table provides a summary of the effect on our consolidated statements of income for the three and nine months ended September 30, 2013 and 2014 of derivatives accounted for under ASC 815; Derivatives and Hedging—Overall, that were not designated as hedging instruments (in thousands):

Amount of Gain (Loss) Recognized on Derivative

Derivative Instrument	Location of Gain (Loss) Recognized on Derivative	Three Months Ended September 30, 2013	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2014
NYMEX commodity contracts	Product sales revenue	$(2,035)	$47,545	$8,546	$33,715
NYMEX commodity contracts	Operating expenses	(3,107)	4,350	(1,645)	447
CME butane futures agreements	Cost of product sales	2,878	(3,913)	2,117	(3,137)
	Total	$(2,264)	$47,982	$9,018	$31,025

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

The impact of the derivatives in the above table was reflected as cash from operations on our consolidated statements of cash flows.

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, 2013 and September 30, 2014 (in thousands):

	December 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	$146
NYMEX commodity contracts	Other noncurrent assets	2,235	Other noncurrent liabilities	—
	Total	$2,235	Total	$146

	September 30, 2014			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$30	Energy commodity derivatives contracts, net	$—
NYMEX commodity contracts	Other noncurrent assets	—	Other noncurrent liabilities	70
Interest rate contracts	Other current assets	713	Other current liabilities	2,543
	Total	$743	Total	$2,613

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, 2013 and September 30, 2014 (in thousands):

	December 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	$48	Energy commodity derivatives contracts, net	$7,021
CME butane futures agreements	Energy commodity derivatives contracts, net	382	Energy commodity derivatives contracts, net	—
	Total	$430	Total	$7,021

	September 30, 2014			
	Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
NYMEX commodity contracts	Energy commodity derivatives contracts, net	$31,879	Energy commodity derivatives contracts, net	$897
CME butane futures agreements		—		3,255

Energy commodity derivatives contracts, net		Energy commodity derivatives contracts, net	
Total	$31,879	Total	$4,152

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

10. Commitments and Contingencies

Environmental Liabilities

Liabilities recognized for estimated environmental costs were $38.5 million and $37.3 million at December 31, 2013 and September 30, 2014, 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 for the three and nine months ended September 30, 2013 were $2.9 million and $(5.8) million, respectively, and the year-to-date amount included a $10.6 million favorable adjustment to a Clean Air Act – Section 185 liability recognized in second quarter 2013. Environmental expenses for the three and nine months ended September 30, 2014 were $3.7 million and $4.1 million, respectively.

Environmental Receivables

Receivables from insurance carriers and other third parties related to environmental matters at December 31, 2013 were $4.8 million, of which $2.1 million and $2.7 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 September 30, 2014 were $5.2 million, of which $1.4 million and $3.8 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheet.

Other

In January 2014, we placed into operation a 36-mile pipeline we constructed in Texas and New Mexico at a cost of approximately $36.4 million. We entered into a long-term throughput and deficiency agreement with a customer on this pipeline, which contains minimum volume/payment commitments. This agreement is being accounted for as a direct financing lease.

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.

11. Long-Term Incentive Plan

We have a long-term incentive plan ("LTIP") for certain of our employees and for directors of our general partner. The LTIP primarily consists of phantom units and permits the grant of awards covering an aggregate payout of 9.4 million of our limited partner units. The estimated units available under the LTIP at September 30, 2014 total 1.4 million. The compensation committee of our general partner's board of directors administers our LTIP.

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

	Three Months Ended September 30, 2013			Nine Months Ended September 30, 2013		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
Performance-based awards:						
2010 awards	$—	$—	$—	$121	$73	$194
2011 awards	1,101	717	1,818	4,204	2,940	7,144
2012 awards	856	432	1,288	2,563	1,413	3,976
2013 awards	763	223	986	2,222	610	2,832
Retention awards	125	—	125	353	—	353
Total	$2,845	$1,372	$4,217	$9,463	$5,036	$14,499
Allocation of LTIP expense on our consolidated statements of income:						
G&A expense			$4,126			$13,928
Operating expense			91			571
Total			$4,217			$14,499

	Three Months Ended September 30, 2014			Nine Months Ended September 30, 2014		
	Equity Method	Liability Method	Total	Equity Method	Liability Method	Total
Performance/market-based awards:						
2012 awards	$1,022	$651	$1,673	$3,066	$3,192	$6,258
2013 awards	1,350	558	1,908	4,726	2,411	7,137
2014 awards	1,101	—	1,101	3,233	—	3,233
Retention awards	296	—	296	1,103	—	1,103
Total	$3,769	$1,209	$4,978	$12,128	$5,603	$17,731
Allocation of LTIP expense on our consolidated statements of income:						
G&A expense			$4,862			$17,322
Operating expense			116			409
Total			$4,978			$17,731

During 2014, 219,282 phantom unit awards were issued pursuant to our LTIP. These grants included both performance-based and retention awards and have a three-year vesting period.

On February 3, 2014, we issued 388,819 limited partner units, of which 387,216 were issued to settle unit award grants to certain employees that vested on December 31, 2013 and 1,603 were issued to settle the equity-based retainer paid to a member of our general partner's board of directors.

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Basic and Diluted Net Income Per Limited Partner Unit

The difference between the weighted-average number of limited partner units outstanding used for basic and diluted net income per unit calculations on our consolidated statements of income is the dilutive effect of phantom unit grants associated with our long-term incentive plan.

12. Distributions
Distributions we paid during 2013 and 2014 were as follows (in thousands, except per unit amounts):

Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution to Limited Partners
02/14/2013	$0.5000	$113,340
05/15/2013	0.5075	115,040
08/14/2013	0.5325	120,707
Through 09/30/2013	1.5400	349,087
11/14/2013	0.5575	126,374
Total	$2.0975	$475,461
02/14/2014	$0.5850	$132,835
05/15/2014	0.6125	139,079
08/14/2014	0.6400	145,324
Through 09/30/2014	1.8375	417,238
11/14/2014[1]	0.6675	151,568
Total	$2.5050	$568,806

(1) Our general partner's board of directors declared this cash distribution on October 22, 2014 to be paid on November 14, 2014 to unitholders of record at the close of business on November 7, 2014.

13. Fair Value

Recurring

Fair Value Methods and Assumptions - Financial Assets and Liabilities.

We used the following methods and assumptions in estimating fair value for our financial assets and liabilities:

- Energy commodity derivatives contracts. These include NYMEX futures and CME 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 9 – Derivative Financial Instruments for further disclosures regarding these contracts.

- Long-term receivables. These include lease payments receivable under a direct-financing leasing arrangement and insurance receivables. Fair value was determined by estimating the present value of future cash flows using current market rates.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
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- Debt. The fair value of our publicly traded notes was based on the prices of those notes at December 31, 2013 and September 30, 2014; however, where recent observable market trades were not available, prices were determined using adjustments to the last traded value for that debt issuance or by adjustments to the prices of similar debt instruments of peer entities that are actively traded. The carrying amount of borrowings, if any, under our revolving credit facility and our commercial paper program approximates fair value due to the frequent repricing of these obligations.

Fair Value Measurements - Financial Assets and Liabilities

The following tables summarize the carrying amounts, fair values and recurring fair value measurements recorded or disclosed as of December 31, 2013 and September 30, 2014, based on the three levels established by ASC 820; Fair Value Measurements and Disclosures (in thousands):

	As of December 31, 2013				
			Fair Value Measurements using:		
Assets (Liabilities)	Carrying Amount	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivatives contracts (liabilities)	$(4,502)	$(4,502)	$(4,502)	$—	$—
Long-term receivables	$2,730	$2,658	$—	$—	$2,658
Debt	$(2,685,287)	$(2,815,210)	$—	$(2,815,210)	$—

	As of September 30, 2014				
			Fair Value Measurements using:		
Assets (Liabilities)	Carrying Amount	Fair Value	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivatives contracts (assets)	$27,687	$27,687	$27,687	$—	$—
Long-term receivables	$29,815	$30,838	$—	$—	$30,838
Debt	$(3,003,707)	$(3,261,107)	$—	$(3,261,107)	$—

14. 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 butane from subsidiaries of Targa. For the three months ended September 30, 2013 and 2014, we made purchases of butane from subsidiaries of Targa of $1.0 million and less than $0.1 million, respectively. For the nine months ended September 30, 2013 and 2014, we made purchases of butane from subsidiaries of Targa of $15.6 million and $13.9 million, respectively. These purchases were made on the same terms as comparable third-party transactions. There were no amounts payable to Targa at December 31, 2013 or September 30, 2014.

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

15. Subsequent Events

Recognizable events

No recognizable events occurred during the period.

Non-recognizable events

In October 2014, our general partner's board of directors declared a quarterly distribution of $0.6675 per unit to be paid on November 14, 2014 to unitholders of record at the close of business on November 7, 2014. The total cash distributions expected to be paid are $151.6 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 September 30, 2014, our asset portfolio, including the assets of our joint ventures, consisted of:

- our refined products segment, including our 9,500-mile refined products pipeline system with 54 terminals as well as 27 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

- our crude oil segment, comprised of approximately 1,600 miles of crude oil pipelines and storage facilities with an aggregate storage capacity of approximately 20 million barrels, of which 12 million is used for leased storage. BridgeTex Pipeline Company, LLC ("BridgeTex") began commercial service in September 2014 and is now included in the pipeline miles and storage capacity amounts of our crude oil segment; and

- our marine storage segment, consisting of five marine terminals located along coastal waterways with an aggregate storage capacity of approximately 27 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 and (ii) our consolidated financial statements, related notes and management’s discussion and analysis of financial condition and results of operations included in our Annual Report on Form 10-K for the year ended December 31, 2013.

Recent Developments

BridgeTex Pipeline. BridgeTex began commercial service in September 2014, delivering crude oil from West Texas to the Houston Gulf Coast area. Initial flow rates are expected to ramp up over time, as the BridgeTex Pipeline is capable of transporting up to 300,000 barrels per day of crude oil from the Permian Basin to the Houston area. We do not consolidate BridgeTex in our financial statements; however, we will recognize our 50% share of its profits in our consolidated statements of income as earnings of non-controlled entities.

Saddlehorn Pipeline. On October 31, 2014, we announced our plans to construct a pipeline to transport crude oil from the Niobrara play in northeast Colorado to our storage facilities in Cushing, Oklahoma. The Saddlehorn Pipeline includes construction of an approximate 600-mile pipeline capable of transporting up to 400,000 barrels per day of crude oil. We have entered into letters of intent with Anadarko Petroleum Corporation and Saddle Butte Pipeline II, LLC for potential equity ownership in Saddlehorn Pipeline. Potential customers must provide binding commitments for this pipeline through the current open season, which runs through November 20, 2014. The project scope, cost and ownership structure of the Saddlehorn Pipeline will be finalized after the open season closes and the total committed volumes are known.

Cash Distribution. In October 2014, the board of directors of our general partner declared a quarterly cash distribution of $0.6675 per unit for the period of July 1, 2014 through September 30, 2014. This quarterly cash distribution will be paid on November 14, 2014 to unitholders of record on November 7, 2014. Total distributions expected to be paid under this declaration are approximately $151.6 million.

Results of Operations

We believe that investors benefit from having access to the same financial measures utilized by management. Operating margin, which is presented in the following tables, is an important measure used by management to

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evaluate the economic performance of our core operations. Operating margin is not a generally accepted accounting principles ("GAAP") measure, but the components of operating margin are computed using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the following tables. Operating profit includes expense items, such as depreciation and amortization expense and general and administrative ("G&A") expenses, which management does not focus on when evaluating the core profitability of our separate operating segments. Additionally, product margin, which management primarily uses to evaluate the profitability of our commodity-related activities, is provided in these tables. Product margin is a non-GAAP measure; however, its components of product sales revenue and cost of product sales are determined in accordance with GAAP. Our butane blending, fractionation and other commodity-related activities generate significant product revenue. We believe the product margin from these activities, which takes into account the related cost of product sales, better represents its importance to our results of operations.

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Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2014

	Three Months Ended September 30,		Variance Favorable (Unfavorable)	
	2013	2014	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenue:				
Refined products	$205.9	$238.0	$32.1	16
Crude oil	49.5	78.8	29.3	59
Marine storage	39.9	43.7	3.8	10
Total transportation and terminals revenue	295.3	360.5	65.2	22
Affiliate management fee revenue	3.6	5.2	1.6	44
Operating expenses:				
Refined products	82.1	101.2	(19.1)	(23)
Crude oil	4.1	14.4	(10.3)	(251)
Marine storage	17.8	17.7	0.1	1
Intersegment eliminations	(0.8)	(0.9)	0.1	13
Total operating expenses	103.2	132.4	(29.2)	(28)
Product margin:				
Product sales revenue	144.9	155.9	11.0	8
Cost of product sales	120.3	91.6	28.7	24
Product margin(1)	24.6	64.3	39.7	161
Earnings of non-controlled entities	2.4	1.7	(0.7)	(29)
Operating margin	222.7	299.3	76.6	34
Depreciation and amortization	35.3	38.1	(2.8)	(8)
G&A expense	32.8	35.4	(2.6)	(8)
Operating profit	154.6	225.8	71.2	46
Interest expense (net of interest income and interest capitalized)	27.9	25.4	2.5	9
Debt placement fee amortization expense	0.5	0.6	(0.1)	(20)
Income before provision for income taxes	126.2	199.8	73.6	58
Provision for income taxes	0.6	1.2	(0.6)	(100)
Net income	$125.6	$198.6	$73.0	58
Operating Statistics:				
Refined products:				
Transportation revenue per barrel shipped	$1.306	$1.408		
Volume shipped (million barrels):				
Gasoline	61.9	66.2		
Distillates	36.1	41.6		
Aviation fuel	5.9	6.4		
Liquefied petroleum gases	4.0	4.3		
Total volume shipped	107.9	118.5		
Crude oil:				
Transportation revenue per barrel shipped	$1.010	$1.304		
Volume shipped (million barrels)	28.6	44.0		
Crude oil terminal average utilization (million barrels per month)	12.3	12.3		
Marine storage:				

Marine terminal average utilization (million barrels per month)	23.2	22.9

(1) Product margin does not include depreciation or amortization expense.

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Transportation and terminals revenue increased $65.2 million resulting from:

- an increase in refined products revenue of $32.1 million. Excluding the pipeline systems we acquired in the second half of 2013 (under Item 1, see Note 5-Business Combinations for a discussion of these systems), refined products revenue increased $26.4 million primarily due to a 7% increase in transportation volumes on our other pipeline segments, higher weighted average tariff rates and higher ancillary revenues associated with increased activity. Shipments were higher primarily due to increased demand for gasoline and distillates in the markets we serve. Tariff rates were impacted by our mid-year 2014 tariff rate increase of 3.9% and longer-haul shipments (which have a higher rate);
- an increase in crude oil revenue of $29.3 million primarily due to higher crude oil deliveries on our Longhorn pipeline, which represented approximately 95% of the increase. Our Longhorn pipeline averaged approximately 100,000 barrels per day in third quarter 2013, increasing to an average of approximately 240,000 barrels per day in third quarter 2014; and
- an increase in marine storage revenue of $3.8 million primarily due to a one-time $3.1 million adjustment (which increased third quarter 2014 revenues) associated with one of our storage contracts and higher storage rates due to contract renewals and annual escalations.

Affiliate management fee revenue increased $1.6 million due to higher construction management fees related to BridgeTex. The construction management fees we receive are designed to reimburse us for our costs of providing services to BridgeTex during its construction.

Operating expenses increased by $29.2 million primarily resulting from:

- an increase in refined products expenses of $19.1 million. Excluding the pipeline systems we acquired in the second half of 2013, refined products expenses increased $12.8 million primarily due to higher asset integrity, personnel and property tax costs, as well as other miscellaneous costs (such as power costs) due to higher volumes; and
- an increase in crude oil expenses of $10.3 million primarily due to higher shipments on our Longhorn pipeline in the current period, including higher power expenses, as well as higher personnel costs and asset integrity spending on our crude oil assets, partially offset by more favorable product overages, which reduce operating expenses.

Product sales revenue 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. Product sales revenue also included 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. We use Chicago Mercantile Exchange ("CME") 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 cost of product sales. See Other Items—Commodity Derivative Agreements—Impact of Commodity Derivatives on Results of Operations below for more information about our NYMEX and CME contracts. Product margin increased $39.7 million primarily attributable to higher unrealized and realized gains recognized on NYMEX contracts in the current quarter.

Earnings of non-controlled entities decreased $0.7 million primarily due to lower earnings related to Osage Pipe Line Company, LLC ("Osage") and Double Eagle Pipeline LLC ("Double Eagle").

Depreciation and amortization increased $2.8 million primarily due to expansion capital projects placed into service since third quarter 2013.

G&A expense increased $2.6 million primarily due to higher personnel costs resulting from an increase in employee headcount and higher equity-based compensation costs reflecting a higher price for our limited partner units.

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Interest expense, net of interest income and interest capitalized, decreased $2.5 million principally due to higher capitalized interest resulting from capital spending primarily related to the BridgeTex pipeline project. Our average outstanding debt increased from $2.5 billion in third quarter 2013 to $3.0 billion in third quarter 2014 primarily due to borrowings for expansion capital expenditures, including $300.0 million of 5.15% senior notes issued in October 2013 and $250.0 million of 5.15% senior notes issued in March 2014. Our weighted-average interest rate decreased from 5.1% in third quarter 2013 to 4.7% in third quarter 2014 primarily due to the impact of our commercial paper borrowings, which are at a lower rate.

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Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2014

	Nine Months Ended September 30,		Variance Favorable (Unfavorable)	
	2013	2014	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenue:				
Refined products	$573.6	$680.7	$107.1	19
Crude oil	113.9	226.3	112.4	99
Marine storage	117.5	124.7	7.2	6
Total transportation and terminals revenue	805.0	1,031.7	226.7	28
Affiliate management fee revenue	10.6	15.3	4.7	44
Operating expenses:				
Refined products	194.9	249.7	(54.8)	(28)
Crude oil	13.2	35.3	(22.1)	(167)
Marine storage	40.0	48.3	(8.3)	(21)
Intersegment eliminations	(2.3)	(2.5)	0.2	9
Total operating expenses	245.8	330.8	(85.0)	(35)
Product margin:				
Product sales revenue	504.5	589.6	85.1	17
Product purchases	396.0	398.7	(2.7)	(1)
Product margin(1)	108.5	190.9	82.4	76
Earnings of non-controlled entities	5.2	4.1	(1.1)	(21)
Operating margin	683.5	911.2	227.7	33
Depreciation and amortization	105.8	122.5	(16.7)	(16)
G&A expense	96.1	109.6	(13.5)	(14)
Operating profit	481.6	679.1	197.5	41
Interest expense (net of interest income and interest capitalized)	84.6	86.1	(1.5)	(2)
Debt placement fee amortization expense	1.6	1.8	(0.2)	(13)
Income before provision for income taxes	395.4	591.2	195.8	50
Provision for income taxes	3.2	3.8	(0.6)	(19)
Net income	$392.2	$587.4	$195.2	50
Operating Statistics:				
Refined products:				
Transportation revenue per barrel shipped	$1.274	$1.392		
Volume shipped (million barrels):				
Gasoline	174.6	189.7		
Distillates	105.4	119.6		
Aviation fuel	15.4	17.5		
Liquefied petroleum gases	7.3	9.5		
Total volume shipped	302.7	336.3		
Crude oil:				
Transportation revenue per barrel shipped	$0.765	$1.222		
Volume shipped (million barrels)	72.6	132.7		
Crude oil terminal average utilization (million barrels per month)	12.4	12.2		
Marine storage:				
Marine terminal average utilization (million barrels per month)	22.9	22.8		

(1) Product margin does not include depreciation or amortization expense.

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Transportation and terminals revenue increased $226.7 million resulting from:

- an increase in refined products revenue of $107.1 million. Excluding the pipeline systems we acquired in the second half of 2013 (under Item 1, see Note 5-Business Combinations for a discussion of these systems), refined products revenue increased $81.4 million primarily due to a 5% increase in transportation volumes on our other pipeline segments, higher average rates and higher ancillary revenues associated with increased activity. Shipments were higher primarily due to increased demand for gasoline and distillates in the markets we serve. The average rate per barrel in the current period was impacted by the mid-year 2013 and 2014 tariff rate increases of 4.6% and 3.9%, respectively, and more long-haul shipments at a higher rate;
- an increase in crude oil revenue of $112.4 million primarily due to crude oil deliveries on our Longhorn pipeline, which represented approximately 90% of the increase. Our Longhorn pipeline began delivering crude oil in mid-April 2013, averaging approximately 90,000 barrels per day from its start date through September 30, 2013. For the nine months ended 2014, Longhorn volumes increased to an average of approximately 230,000 barrels per day; and
- an increase in marine storage revenue of $7.2 million primarily due to higher storage rates from contract renewals and annual escalations and a one-time $3.1 million adjustment (which increased 2014 revenues) associated with one of our storage contracts.

Affiliate management fee revenue increased $4.7 million due to higher construction management fees related to BridgeTex. The construction management fees we receive are designed to reimburse us for our costs of providing services to BridgeTex during its construction.

Operating expenses increased by $85.0 million resulting from:

- an increase in refined products expenses of $54.8 million. Excluding the pipeline systems we acquired in the second half of 2013, refined products expenses increased $37.3 million primarily due to additional costs in the current year for asset integrity, property taxes, power, personnel and pipeline rental primarily related to a pipeline segment we began leasing in 2014 and lower product overages, which reduce operating expenses, as well as a favorable adjustment in 2013 of an accrual for potential air emission fees at our East Houston facility;
- an increase in crude oil expenses of $22.1 million primarily due to higher shipments on our Longhorn pipeline in the current period, including higher power expenses, as well as higher personnel costs, asset integrity expense and pipeline rental fees, partially offset by more favorable product overages, which reduce operating expenses; and
- an increase in marine storage expenses of $8.3 million primarily due to a favorable adjustment in 2013 of an accrual for potential air emission fees at our Galena Park facility, and higher asset integrity costs in the current period.

Product margin increased $82.4 million primarily attributable to higher margins from our butane blending activities as a result of higher sales volumes and lower butane costs, partially offset by lower sales prices. The increased volume was primarily attributable to selling gasoline production volumes carried over from our fourth quarter 2013 blending activities as well as capturing additional blending opportunities this year. Also contributing to the higher margins were higher unrealized gains recognized on NYMEX contracts in the current year.

Earnings of non-controlled entities decreased $1.1 million primarily due to lower earnings related to Osage and Double Eagle.

Depreciation and amortization increased $16.7 million primarily due to a $9.4 million impairment of a certain terminal and related assets, which we charged to depreciation expense during 2014, as well as expansion capital projects placed into service since 2013.

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G&A expense increased $13.5 million primarily due to higher equity-based compensation costs and deferred board of director awards resulting principally from a higher price for our limited partner units and higher personnel costs resulting from an increase in employee headcount.
Interest expense, net of interest income and interest capitalized, increased $1.5 million primarily due to higher borrowings, partially offset by higher amounts of interest capitalized in 2014. Our average outstanding debt increased from $2.4 billion in 2013 to $2.9 billion in 2014 primarily due to borrowings for expansion capital expenditures, including $300.0 million of 5.15% senior notes issued in October 2013 and $250.0 million of 5.15% senior notes issued in March 2014. Our weighted-average interest rate decreased from 5.2% in 2013 to 5.0% in 2014 primarily due to the impact of our commercial paper borrowings, which are at a lower rate.

Distributable Cash Flow

Distributable cash flow ("DCF") and adjusted EBITDA are non-GAAP measures. Management uses DCF as a basis for recommending to our general partner's board of directors the amount of cash distributions to be paid each period. Management also uses DCF to evaluate our ability to generate cash for distribution to our limited partners and as a basis for determining equity-based compensation. Adjusted EBITDA is an important measure that we and the investment community use 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 DCF and adjusted EBITDA for the nine months ended September 30, 2013 and 2014 to net income, which is its nearest comparable GAAP financial measure, follows (in millions):

	Nine Months Ended September 30,		Increase
	2013	2014	(Decrease)
Net income	$392.2	$587.4	$195.2
Interest expense, net, and provision for income taxes	87.7	89.9	2.2
Depreciation and amortization expense(1)	107.4	124.2	16.8
Equity-based incentive compensation expense(2)	2.2	2.9	0.7
Asset retirements	4.3	4.8	0.5
Commodity-related adjustments:			
Derivative gains recognized in the period associated with future product transactions(3)	(8.3)	(28.7)	(20.4)
Derivative losses recognized in previous periods associated with products sold in the period(4)	(5.7)	(8.1)	(2.4)
Lower-of-cost-or-market adjustments	(0.5)	2.5	3.0
Total commodity-related adjustments	(14.5)	(34.3)	(19.8)
Other	(3.0)	3.6	6.6
Adjusted EBITDA	576.3	778.5	202.2
Interest expense, net, and provision for income taxes	(87.7)	(89.9)	(2.2)
Maintenance capital(5)	(55.5)	(56.2)	(0.7)
DCF	$433.1	$632.4	$199.3

(1) Depreciation and amortization expense includes debt placement fee amortization. The 2014 amount includes a $9.4 million impairment of a certain terminal and related assets, which we recorded during second quarter 2014 to depreciation expense.

(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 to net income to calculate DCF. Total equity-based incentive compensation expense for the nine months ended

September 30, 2013 and 2014 was $14.5 million and $17.7 million, respectively. However, the figures above include an adjustment for minimum statutory tax withholdings we paid in 2013 and 2014 of $12.3 million and $14.8 million, respectively, for equity-based incentive compensation units that vested at the previous year end, which reduce DCF.

(3) Certain derivatives we use as economic hedges have not been designated as hedges for accounting purposes and the mark-to-market changes of these derivatives are recognized currently in earnings. These amounts represent the gains or losses from economic hedges in our earnings for the period associated with products that had not yet been physically sold as of the period-end date.

(4) When we physically sell products that we have economically hedged (but were not designated as hedges for accounting purposes), we include in our DCF calculations the full amount of the change in fair value of the associated derivative agreement.

(5) Maintenance capital expenditure projects maintain our existing assets and do not generate incremental distributable cash flow (i.e. incremental returns to our unitholders), while expansion capital projects are undertaken primarily to generate incremental distributable cash flow. For this reason, we deduct maintenance capital expenditures to determine distributable cash flow.

A reconciliation of DCF to cash distributions paid is as follows (in millions):

	Nine Months Ended September 30,	
	2013	2014
Distributable cash flow	$433.1	$632.4
Less: Cash reserves approved by our general partner	84.0	215.2
Total cash distributions paid	$349.1	$417.2

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $526.2 million and $713.3 million for the nine months ended September 30, 2013 and 2014, respectively. The $187.1 million increase from 2013 to 2014 was primarily attributable to:

- a $211.9 million increase in net income and non-cash depreciation and amortization; and
- a $22.0 million increase resulting from a $10.9 million decrease in trade accounts receivable and other accounts receivable in 2014 versus an $11.1 million increase during 2013, primarily due to timing of payments from our customers.

These increases were partially offset by:

- a $28.7 million decrease resulting from a $15.3 million increase in inventory in 2014 versus a $13.4 million decrease in inventory in 2013 primarily due to increased inventories from product overages on our pipeline systems; and
- a $14.0 million decrease resulting from a $7.5 million increase in deferred revenue in 2014 versus a $21.5 million increase in deferred revenue in 2013. The increase in 2014 was primarily due to an increase in customer prepayments. The increase in 2013 was primarily due to an increase in product-in-transit in our pipeline, an increase related to customers' transportation deficiencies where the customer had rights to use the payment in future periods and a deferral of a sale of an asset where the title had not yet passed, but the cash had been received.

Net cash used by investing activities for the nine months ended September 30, 2013 and 2014 was $577.3 million and $608.8 million, respectively. During 2014, we spent $237.2 million for capital expenditures, which included $56.2 million for maintenance capital and $181.0 million for expansion capital. Also during the 2014 period, we contributed capital of $378.2 million in conjunction with our joint venture capital projects (primarily BridgeTex) which we account for as investments in non-controlled entities. During 2013, we spent $289.7 million for capital expenditures, which included $55.5 million for maintenance capital and $234.2 million for expansion capital. Also during the 2013 period, we contributed capital of $181.4 million in conjunction with our joint venture capital projects which we account for as investments in non-controlled entities, acquired a 250-mile pipeline business for $57.0 million and spent $22.5 million on an asset acquisition.

Net cash used by financing activities for the nine months ended September 30, 2013 and 2014 was $262.9 million and $114.9 million, respectively. During 2014, we paid cash distributions of $417.2 million to our unitholders. Additionally, we received net proceeds of $257.7 million from borrowings under long-term notes and $316.0 million from borrowings under our commercial paper program, which were used in part to repay our $250.0 million of 6.45% notes due June 1, 2014, to repay borrowings outstanding under our revolving credit facility and for general partnership purposes, including expansion capital. Also, in January 2014, the cumulative amounts of the January 2011 equity-based incentive compensation award grants were settled by issuing 387,216 limited partner units and distributing those units to the long-term incentive plan ("LTIP") participants, resulting in payments of associated tax withholdings of $14.8 million. During 2013, we paid cash distributions of $349.1 million to our unitholders and borrowed $98.4 million on our revolving credit facility. 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 LTIP participants, resulting in payments of associated tax withholdings of $12.3 million. The quarterly distribution amount related to our third-quarter 2014 financial results (to be paid in fourth quarter 2014) is $0.6675 per unit. If we meet management's targeted distribution growth of 20% for 2014 and the number of outstanding limited partner units remains unchanged at 227.1 million, total cash distributions of approximately $593.8 million will be paid to our unitholders related to 2014 financial results. Management believes we will have sufficient distributable cash flow to fund these distributions.

Capital Requirements

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

- Maintenance capital expenditures. These expenditures include costs required to maintain equipment reliability and safety and to address environmental or other regulatory requirements rather than to generate incremental distributable cash flow; and
- Expansion capital expenditures. These expenditures are undertaken primarily to generate incremental distributable cash flow and include costs to acquire additional assets to grow our business and to expand or upgrade our existing facilities, which we refer to as organic growth projects. Organic growth projects include capital expenditures that increase storage or throughput volumes or develop pipeline connections to new supply sources.

For the nine months ended September 30, 2014, our maintenance capital spending was $56.2 million. For 2014, we expect to spend approximately $77.0 million on maintenance capital.

During the first nine months of 2014, we spent $181.0 million for organic growth capital and $378.2 million for capital projects in conjunction with our joint ventures. Based on the progress of expansion projects already underway, including the expansion of our Longhorn crude oil pipeline, construction of a condensate splitter at Corpus Christi, Texas and pipeline segment to Little Rock, Arkansas and our investment in the BridgeTex pipeline, we expect to spend approximately $775.0 million for expansion capital and joint venture capital contributions during 2014, with an additional $450.0 million in 2015 and $75.0 million in 2016 to complete our current projects. Our capital spending projections do not include costs associated with the recently-announced Saddlehorn Pipeline project at this time.

Liquidity

Consolidated debt at December 31, 2013 and September 30, 2014 was as follows (in millions, except as otherwise noted):

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	December 31, 2013	September 30, 2014	Weighted-Average Interest Rate for Nine Months Ending September 30, 2014 (1)
Commercial paper(2)	$—	$316.0	0.3%
Revolving credit facility(2)	—	—	1.3%
$250.0 of 6.45% Notes due 2014(2)	250.0	—	6.3%
$250.0 of 5.65% Notes due 2016	251.2	250.9	5.7%
$250.0 of 6.40% Notes due 2018	259.3	257.8	5.4%
$550.0 of 6.55% Notes due 2019	571.5	568.8	5.7%
$550.0 of 4.25% Notes due 2021	557.2	556.5	4.0%
$250.0 of 6.40% Notes due 2037	249.0	249.0	6.4%
$250.0 of 4.20% Notes due 2042	248.4	248.4	4.2%
$550.0 ($300.0 million at December 31, 2013) of 5.15% Notes due 2043(2)	298.7	556.3	5.1%
Total debt	$2,685.3	$3,003.7	5.0%

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

(2) These borrowings were outstanding for only a portion of the nine month period ending September 30, 2014. The weighted-average interest rate for these borrowings was calculated based on the number of days the borrowings were outstanding during the noted period.

All of the instruments detailed in the table above are senior indebtedness.

The face value of our debt at December 31, 2013 and September 30, 2014 was $2.7 billion and $3.0 billion, respectively. The difference between the face value and carrying value of the debt outstanding is the unamortized portion of 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.

2014 Debt Offering

In March 2014, we issued $250.0 million of our 5.15% notes due October 15, 2043 in an underwritten public offering. The notes were issued at 103.1% of par. We used the net proceeds from this offering of approximately $255.0 million, after underwriting discounts and offering expenses of $2.7 million, to repay borrowings outstanding under our revolving credit facility and for general partnership purposes, including expansion capital.

Other Debt

Revolving Credit Facility. The total borrowing capacity under our revolving credit facility, which matures in November 2018, is $1.0 billion. Borrowings outstanding under the facility are classified as long-term debt on our consolidated balance sheets. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 1.0% to 1.75% based on our credit ratings. Additionally, an unused commitment fee is assessed at a rate from 0.10% to 0.28%, depending on our credit ratings. The unused commitment fee was 0.125% at September 30,

2014. Borrowings under this facility may be used for general partnership purposes, including capital expenditures. As of September 30, 2014, there were no borrowings outstanding under this facility and $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.

Commercial Paper Program. In April 2014, we initiated a commercial paper program. The maturities of the commercial paper notes vary, but may not exceed 397 days from the date of issuance. The commercial paper notes are sold under customary terms in the commercial paper market and are issued at a discount from par, or alternatively, are sold at par and bear varying interest rates on a fixed or floating basis. The commercial paper we can issue is limited by the amounts available under our revolving credit facility up to an aggregate principal amount of $1.0 billion. We have the ability and intent to refinance all of our commercial paper obligations on a long-term basis; therefore, we have elected to classify our commercial paper borrowings outstanding as long-term debt on our consolidated balance sheets. In second quarter 2014, proceeds from commercial paper borrowings were used in part to repay our $250.0 million of 6.45% senior notes that were due June 1, 2014. Additional commercial paper borrowings have been used for general partnership purposes, including expansion capital.

Interest Rate Derivatives. In third quarter 2014, we entered into $200.0 million of forward-starting interest rate swap agreements to hedge against the risk of variability of future interest payments on a portion of debt we anticipate issuing in the next year. The fair value of these contracts at September 30, 2014 was a net liability of $1.8 million. We account for these agreements as cash flow hedges.

In first quarter 2014, we entered into $200.0 million of interest rate swap agreements to hedge against the variability of future interest payments on an anticipated debt issuance. We accounted for these agreements as cash flow hedges. When we issued $250.0 million of 5.15% notes due 2043 later in the first quarter of 2014, we settled the associated interest rate swap agreements for a loss of $3.6 million. The loss was recorded to other comprehensive income and is being recognized into earnings as an adjustment to our periodic interest expense accruals over the life of the associated notes. This loss was also reported as net payment on financial derivatives in the financing activities of our consolidated statements of cash flows.

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 as a deferred cash flow hedging gain. The purpose of these swaps was to hedge against the variability of future interest payments on the refinancing of our debt that matured in June 2014. We recognized ineffectiveness in earnings on this deferred hedging gain of $0.2 million for the nine months ended September 30, 2014 due to timing of our debt refinancing.

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.

Other Items

Condensate Splitter. In March 2014, we announced plans to construct a condensate splitter at our terminal in Corpus Christi, Texas under a fee-based, take-or-pay agreement with a third-party customer. The project also includes construction of more than one million barrels of storage, dock improvements and two additional truck rack bays at our terminal as well as pipeline connectivity between our terminal and a nearby third-party facility. The splitter will be capable of processing 50,000 barrels per day of condensate. We expect the condensate splitter and related infrastructure to cost approximately $250 million and to be operational during the second half of 2016, subject to receipt of necessary permits and authorizations.

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Little Rock Pipeline. In May 2014, we announced plans to transport refined products from our Ft. Smith, Arkansas terminal to Little Rock, Arkansas. We have entered into an agreement with a third party to utilize an existing pipeline for a portion of the route, which we will extend to our Ft. Smith terminal and to the Little Rock market with approximately 50 miles of newly-constructed pipeline. We further plan to make enhancements to our pipeline system to accommodate additional volumes. The Little Rock pipeline project is expected to cost approximately $150 million and to be operational in early 2016, subject to receipt of regulatory and other approvals.

Commodity 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 forward physical commodity contracts, NYMEX contracts and CME butane futures agreements to help manage this commodity price risk. We use forward physical contracts to purchase butane and sell refined products. We account for these forward physical contracts as normal purchase and sale contracts, using traditional accrual accounting. 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 CME 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 activities. As of September 30, 2014, our open NYMEX and CME 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 October 2014 and November 2016. Through September 30, 2014, the cumulative amount of losses from these agreements was $11.0 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 have impacted our consolidated income statement.

Open Derivative Contracts Not Designated as Hedges

- NYMEX contracts covering 3.5 million barrels of refined products related to our butane blending and fractionation activities. These contracts mature between October 2014 and October 2015 and are being accounted for as economic hedges. Through September 30, 2014, the cumulative amount of net unrealized gains associated with these agreements was $29.9 million. We recorded these gains as an adjustment to product sales revenue, all of which was recognized in 2014.

- NYMEX contracts covering 0.5 million barrels of refined products and crude oil related to inventory we carry that resulted from pipeline product overages. These contracts, which mature between October 2014 and October 2015, are being accounted for as economic hedges. Through September 30, 2014, the cumulative amount of net unrealized gains associated with these agreements was $1.0 million. We recorded these gains as an adjustment to operating expenses, all of which was recognized in 2014.

- CME-traded butane futures agreements to purchase 0.9 million barrels of butane that mature between October 2014 and April 2015, which are being accounted for as economic hedges. Through September 30, 2014, the cumulative amount of net unrealized losses associated with these agreements was $3.2 million. We recorded these losses as an adjustment to cost of product sales, all of which was recognized in 2014.

Settled Derivative Contracts

- We settled NYMEX contracts covering 6.5 million barrels of refined products related to economic hedges of products from our butane blending and fractionation activities that we sold during 2014. We recognized a gain of $3.8 million in 2014 related to these contracts, which we recorded as an adjustment to product sales revenue.

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- We settled NYMEX contracts covering 4.1 million barrels of refined products and crude oil related to economic hedges of product inventories from product overages on our pipeline system that we sold during 2014. We recognized a loss of $0.6 million in 2014 on the settlement of these contracts, which we recorded as an adjustment to operating expense.

- We settled CME butane futures agreements covering 0.2 million barrels related to economic hedges of butane purchases we made during 2014 associated with our butane blending activities. We recognized a gain of $0.1 million in the current period on the settlement of these contracts, which we recorded as an adjustment to cost of product sales.

Impact of Commodity Derivatives on Results of Operations

The following tables provide a summary of the positive and (negative) impacts of the mark-to-market gains and losses associated with NYMEX and CME contracts on our results of operations for the respective periods presented (in millions):

	Three Months Ended September 30, 2013			
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Net Impact on Results of Operations
NYMEX and CME gains (losses) recognized during the period that were associated with economic hedges of physical product sales or purchases during the period	$(3.3)	$0.3	$(3.6)	$(6.6)
NYMEX and CME gains recorded during the period that were associated with products that will be or were sold or purchased in future periods	1.3	2.6	0.5	4.4
Net impact of NYMEX and CME contracts	$(2.0)	$2.9	$(3.1)	$(2.2)

	Three Months Ended September 30, 2014			
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Net Impact on Results of Operations
NYMEX and CME gains (losses) recognized during the period that were associated with economic hedges of physical product sales or purchases during the period	$6.5	$(0.1)	$3.3	$9.7
NYMEX and CME gains (losses) recorded during the period that were associated with products that will be sold or purchased in future periods	41.0	(3.8)	1.1	38.3
Net impact of NYMEX and CME contracts	$47.5	$(3.9)	$4.4	$48.0

	Nine Months Ended September 30, 2013			
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Net Impact on Results of Operations
	$(0.9)	$(0.6)	$(2.1)	$(3.6)

NYMEX and CME losses recognized during the period that were associated with economic hedges of physical product sales or purchases during the period				
NYMEX and CME gains recorded during the period that were associated with products that will be or were sold or purchased in future periods	5.0	2.7	0.5	8.2
Net impact of NYMEX and CME contracts	$4.1	$2.1	$(1.6)	$4.6

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	Nine Months Ended September 30, 2014			
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Net Impact on Results of Operations
NYMEX and CME gains (losses) recognized during the period that were associated with economic hedges of physical product sales or purchases during the period	$3.8	$0.1	$(0.6)	$3.3
NYMEX and CME gains (losses) recorded during the period that were associated with products that will be sold or purchased in future periods	29.9	(3.2)	1.0	27.7
Net impact of NYMEX and CME contracts	$33.7	$(3.1)	$0.4	$31.0

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 butane from subsidiaries of Targa. For the three months ended September 30, 2013 and 2014, we made purchases of butane from subsidiaries of Targa of $1.0 million and less than $0.1 million, respectively. For the nine months ended September 30, 2013 and 2014, we made purchases of butane from subsidiaries of Targa of $15.6 million and $13.9 million, respectively. These purchases were made on the same terms as comparable third-party transactions. There were no amounts payable to Targa at December 31, 2013 or September 30, 2014.

We own a 50% interest in Texas Frontera, LLC ("Texas Frontera"), which owns approximately one million barrels of refined products storage at our Galena Park, Texas terminal. The storage capacity owned by this joint venture is leased to an affiliate of Texas Frontera under a long-term lease agreement. We receive management fees from Texas Frontera, which we report as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in Osage, which owns a 135-mile crude oil pipeline in Oklahoma and Kansas that we operate. We receive management fees from Osage, which we report as affiliate management fee revenue on our consolidated statements of income.

We own a 50% interest in Double Eagle, which transports condensate from the Eagle Ford shale formation in South Texas via a 195-mile pipeline to our terminal in Corpus Christi, Texas. Double Eagle is operated by an affiliate of the other 50% member of Double Eagle. In addition to our equity ownership in Double Eagle, we receive throughput revenue from Double Eagle that is included in our transportation and terminals revenue on our consolidated statements of income. For the three months ended September 30, 2013 and 2014, we received throughput revenue of $0.5 million and $0.7 million, respectively. For the nine months ended September 30, 2013 and 2014, we received throughput revenue of $0.8 million and $2.0 million, respectively. Throughput revenue is reported as transportation and terminalling revenue on our consolidated statements of income. We recognized a $0.2 million and $0.3 million trade accounts receivable from Double Eagle at December 31, 2013 and September 30, 2014, respectively.

We own a 50% interest in BridgeTex, which owns a 450-mile pipeline with related infrastructure to transport crude oil from Colorado City, Texas for delivery to the Houston Gulf Coast area. BridgeTex began commercial service to the Houston Gulf Coast region during September 2014. We receive management fees from BridgeTex, which we report as affiliate management fee revenue on our consolidated statements of income.

We received $4.8 million from BridgeTex in 2013 as a deposit for the purchase of emission reduction credits, which were necessary for the operation of BridgeTex's tanks in East Houston, Texas. In second quarter 2014, we transferred these emission reduction credits to BridgeTex and recorded $2.4 million as a reduction of operating expense. We recorded the remaining $2.4 million as an adjustment to our investment in BridgeTex, which we are amortizing to earnings of non-controlled entities over the weighted average depreciable lives of the BridgeTex assets. Also during 2013, we received $1.4 million from BridgeTex for the purchase of easement rights from us, of which $0.7 million was recorded as a reduction of operating expense and $0.7 million was recorded as an adjustment to our investment in BridgeTex, which we are amortizing to earnings of non-controlled entities over the weighted average depreciable lives of the BridgeTex assets.

New Accounting Pronouncements

In August 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update (“ASU”) No. 2014-15, Presentation of Financial Statements-Going Concern (Subtopic 205-40): Disclosure of Uncertainties About an Entity’s Ability to Continue as a Going Concern. This standard requires management to assess an entity’s ability to continue as a going concern, and to provide related footnote disclosures in certain circumstances. Before this new standard, no accounting guidance existed for management on when and how to assess or disclose going concern uncertainties. The amendments apply to all companies and not-for-profit organizations. They will take effect in the annual periods ending after December 15, 2016, and interim periods within annual periods beginning after December 15, 2016. Early application is permitted.

In June 2014, the FASB issued ASU 2014-12, Compensation-Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period. This ASU finalizes the Emerging Issues Task Force’s Proposed ASU No. EITF-13D of the same name, and seeks to resolve the diversity in practice that exists when accounting for share-based payments. This ASU requires that a performance target that affects vesting and can be achieved after the requisite service period to be accounted for as a performance condition. The new standard is effective for annual and interim periods after December 15, 2015. We do not expect that our adoption of this standard will have a material impact on our results of operation, financial position or cash flows.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers, which eliminates the industry-specific guidance in U.S. GAAP and produces a single, principles-based method for companies to report revenue in their financial statements. The new standard requires companies to make more estimates and use more judgment than under current guidance. In addition, all companies must compile more extensive footnote disclosures about how the revenue numbers were derived. This ASU is effective for periods beginning January 1, 2017 and requires either a full retrospective or modified retrospective adoption. We have not yet determined which adoption method we will employ. Early adoption of this standard is not allowed. We are currently in the process of evaluating the impact this new standard will have on our financial statements.

In April 2014, the FASB issued ASU 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This standard will limit the number of disposals of assets that should be presented as discontinued operations to those disposals that represent a strategic shift in operations and have a major effect on the organization's operations and financial results. Expanded disclosures will be required to provide more information about the assets, liabilities, income and expenses of discontinued operations as well as significant asset disposals that do not meet the criterion for discontinued operations treatment. This ASU will take effect for annual financial statements with fiscal years beginning on or after December 15, 2014. We do not expect the adoption of this standard to impact 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 use derivative agreements to help manage our exposure to commodity price and interest rate risks.

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 September 30, 2014, we had commitments under forward purchase and sale contracts used in our butane blending and fractionation activities as follows (in millions):

	Notional Value	Barrels
Forward purchase contracts	$248.1	4.2
Forward sale contracts	$80.6	0.9

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 as economic hedges. We also use CME-traded butane futures agreements to hedge against changes in the price of butane that we expect to purchase in future periods. At September 30, 2014, we had open NYMEX contracts representing 4.7 million barrels of petroleum products we expect to sell in the future and NYMEX contracts representing 0.8 million barrels of petroleum products that swap the pricing on these barrels from New York harbor to Platts Group 3 or Platts Gulf Coast (the geographic location where these barrels will be sold). Additionally, we had open CME butane futures agreements for 0.9 million barrels of butane we expect to purchase in the future.

At September 30, 2014, the fair value of our open NYMEX contracts was an asset of $31.0 million and the fair value of our CME-traded butane futures agreements was a liability of $3.3 million. Combined, the net asset of $27.7 million was recorded as a current asset to energy commodity derivatives contracts ($27.8 million) and other non-current liabilities ($0.1 million).

At September 30, 2014, open NYMEX contracts representing 4.0 million barrels of petroleum products did not qualify for hedge accounting treatment. A $10.00 per barrel increase in the price of reformulated gasoline blendstock for oxygen blending (“RBOB”) gasoline or heating oil would result in a $40.0 million decrease in our operating profit and a $10.00 per barrel decrease in the price of RBOB or heating oil would result in a $40.0 million increase in our operating profit.

Of the 4.0 million barrels of products we have economically hedged at September 30, 2014, we had open agreements which swap the pricing on 0.8 million of those barrels from New York harbor to Platts Group 3 or Platts Gulf Coast, which are the geographic locations where these barrels will be sold. A $1.00 per barrel increase in the New York harbor price relative to the Platts 3 or Platts Gulf Coast price would result in a $0.8 million decrease to our operating profit and $1.00 per barrel decrease in the New York harbor price relative to the Platts 3 or Platts Gulf Coast price would result in a $0.8 million increase in our operating profit.

At September 30, 2014, we had open CME butane futures agreements representing 0.9 million barrels of butane we expect to purchase in the future. A $10.00 per barrel increase in the price of butane would result in a $9.0 million increase in our operating profit and a $10.00 per barrel decrease in the price of butane would result in a $9.0 million decrease in our operating profit.

The increases or decreases in operating profit we recognize from our open NYMEX forward sales and price swap contracts and open CME butane futures agreements would be substantially offset by higher or lower product

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sales revenue or cost of product sales when the physical sale or purchase of those products occur. 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 and the resulting hedges may not eliminate all price risks.

Interest Rate Risk

At September 30, 2014, we had $316.0 million of commercial paper notes outstanding which represents variable rate debt. We can issue up to $1.0 billion of commercial paper, limited by the amounts available under our revolving credit facility. Considering the amount of commercial paper borrowings outstanding at September 30, 2014, our annual interest expense would change by $0.4 million if rates charged by our commercial paper lenders changed by 0.125%.

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ITEM 4. CONTROLS AND PROCEDURES

We performed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rule 13a-14(c) of the Securities Exchange Act) as of the end of the period covered by the date of this report. We performed this evaluation under the supervision and with the participation of our management, including our general partner's Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner's Chief Executive Officer and Chief Financial Officer concluded that these disclosure controls and practices are effective in providing reasonable assurance that all required disclosures are included in the current report. Additionally, these disclosure controls and practices are effective in ensuring that information required to be disclosed is accumulated and communicated to our Chief Executive Officer and Chief Financial Officer to allow timely decisions regarding required disclosures. There has been no change in our internal control over financial reporting (as defined in Rule 13a-15(f) of the Securities Exchange Act) during the quarter ended September 30, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

In 1992, the Committee of Sponsoring Organizations of the Treadway Commission ("COSO Commission") issued its Internal Control - Integrated Framework for the purpose of helping organizations design, implement and evaluate the effectiveness of their internal controls (the "1992 Framework"). We have been utilizing the 1992 Framework to evaluate the effectiveness of our internal controls since our inception. On May 14, 2013, the COSO Commission issued an updated version of its Internal Control - Integrated Framework (the "2013 Framework"). The COSO Commission has stated that it will consider the 1992 Framework as being superseded by the 2013 Framework after December 15, 2014. We have adopted and are in compliance with the 2013 Framework as of September 30, 2014.

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," "projected," "scheduled," "should," "will" 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

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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, crude oil or marine 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;
- not being adequately insured or having losses that exceed our insurance coverage;
- our ability to obtain insurance and to manage the increased cost of available insurance;
- 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;
- 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 services, 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 or renewable fuel obligations 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, hydraulic fracturing, derivatives transactions, and environmental laws and regulations, including laws and regulations designed to address climate change;
- the cost and effects of legal and administrative claims and proceedings against us or our subsidiaries;
- the amount of our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- the effect of changes in accounting policies;
- the potential that our internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful;
- the ability of third parties to perform on their contractual obligations to us;

- petroleum product supply disruptions;
- global and domestic 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.

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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

2011 EPA Clean Water Act Information Request for Pipeline Release in Texas

In July 2011, we received an information request from the Environmental Protection Agency ("EPA") pursuant to Section 308 of the Clean Water Act regarding a pipeline release in February 2011 in Texas. We have accrued $0.1 million for potential monetary sanctions related to this matter. We are currently meeting with the EPA and Department of Justice ("DOJ") and expect this matter to be resolved in 2015. While the results cannot be predicted with certainty, we believe that the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

2012 Notice of Probable Violation from PHMSA for Oklahoma and Texas

In March 2012, we received a Notice of Probable Violation from the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration ("PHMSA") for alleged violations related to the operation and maintenance of certain pipelines in Oklahoma and Texas. We recently settled this matter with PHMSA and paid a $0.1 million penalty.

2012 EPA Clean Water Act Information Request for Pipeline Release in Nebraska

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 are currently meeting with the EPA and DOJ and expect this matter to be resolved in 2015. We have accrued $0.6 million for potential monetary sanctions related to this matter. While the results cannot be predicted with certainty, we believe that the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

US Oil Recovery, EPA ID No.: TXN000607093 Superfund Site

We have liability at the U.S. Oil Recovery Superfund Site in Pasadena, Texas as a potential responsible party ("PRP") under Section 107(a) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended ("CERCLA"). As a result of the EPA's Administrative Settlement Agreement and Order on Consent for Removal Action, filed August 25, 2011, EPA Region 6, CERCLA Docket No. 06-10-11, we voluntarily entered into the PRP group responsible for the site investigation, stabilization and subsequent site cleanup. 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, known as the assessment phase. We have paid $15,000 associated with the assessment phase. Until this assessment phase has been completed, we cannot reasonably estimate our proportionate share of the remediation costs associated with this site.

We are a party to various other claims, legal actions and complaints arising in the ordinary course of business. While the results cannot be predicted with certainty, management believes the ultimate resolution of these claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification arrangements will not have a material adverse effect on our 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, 2013, which could materially affect our business, financial condition or future results. The risks described in our Annual Report

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on Form 10-K are not our only risks. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

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ITEM 6. EXHIBITS

Exhibit Number		Description
Exhibit 12	—	Ratio of earnings to fixed charges.
Exhibit 31.1	—	Certification of Michael N. Mears, principal executive officer.
Exhibit 31.2	—	Certification of Michael P. Osborne, principal financial officer.
Exhibit 32.1	—	Section 1350 Certification of Michael N. Mears, Chief Executive Officer.
Exhibit 32.2	—	Section 1350 Certification of Michael P. Osborne, 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 October 31, 2014.

MAGELLAN MIDSTREAM PARTNERS, L.P.

By:	Magellan GP, LLC, its general partner

/s/ Michael P. Osborne
Michael P. Osborne
Chief Financial Officer
(Principal Accounting and Financial Officer)

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INDEX TO 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 Michael P. Osborne, principal financial officer.
Exhibit 32.1	—	Section 1350 Certification of Michael N. Mears, Chief Executive Officer.
Exhibit 32.2	—	Section 1350 Certification of Michael P. Osborne, 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.
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