WASHINGTON TRUST BANCORP INC
Form 144
November 06, 2018

	OMB APPROVAL
UNITED STATES SECURITIES AND EXCHANGE COMMISSION Washington, D.C. 20549	OMB Number: 3235-0101 Expires: June 30, 2020 Estimated average burden hours per response…1.00
FORM 144 NOTICE OF PROPOSED SALE OF SECURITIES PURSUANT TO RULE 144 UNDER THE SECURITIES ACT OF 1933	SEC USE ONLY DOCUMENT SEQUENCE NO.
ATTENTION: Transmit for filing 3 copies of this form concurrently with either placing an order with a broker to execute sale or executing a sale directly with a market maker.	CUSIP NUMBER

1 (a) NAME OF ISSUER (Please type or print)	(b) IRS IDENT. NO.	(c) S.E.C. FILE NO.	WORK LOCATION
Washington Trust Bancorp, Inc.	05-0404671	001-32991	

1 (d) ADDRESS OF ISSUER	STREET	CITY	STATE	ZIP CODE	(e) TELEPHONE NO. AREA CODE	NUMBER
	23 Broad Street	Westerly	RI	02891	401	348-1200

2 (a) NAME OF PERSON FOR WHOSE ACCOUNT THE SECURITIES ARE TO BE SOLD	(b) RELATIONSHIP TO ISSUER	(c) ADDRESS STREET	CITY	STATE	ZIP CODE
H. Douglas Randall III	Director	8 Waxcadowa Avenue	Westerly	RI	02891

INSTRUCTION: The person filing this notice should contact the issuer to obtain the I.R.S. Identification Number and the S.E.C. File Number.

3 (a)	(b)	SEC USE ONLY	(c)	(d)	(e)	(f)	(g)
Title of the Class of Securities To Be Sold	Name and Address of Each Broker Through Whom the Securities are to be Offered or Each Market Maker who is Acquiring the Securities	Broker-Dealer File Number	Number of Shares or Other Units To Be Sold (See instr. 3(c))	Aggregate Market Value (See instr. 3(d))	Number of Shares or Other Units Outstanding (See instr. 3(e))	Approximate Date of Sale (See instr. 3(f)) (MO. DAY YR.)	Name of Each Securities Exchange (See instr. 3(g))
Common Stock	Oppenheimer & Company, Inc. PO Box		1,000	$51,280	17,294,570	11/6/2018	NASDAQ

1910, Fall River, MA
02722

INSTRUCTIONS:

1. (a)	Name of issuer	3. (a)	Title of the class of securities to be sold
(b)	Issuer's I.R.S. Identification Number	(b)	Name and address of each broker through whom the securities are intended to be sold
(c)	Issuer's S.E.C. file number, if any	(c)	Number of shares or other units to be sold (if debt securities, give the aggregate face amount)
(d)	Issuer's address, including zip code	(d)	Aggregate market value of the securities to be sold as of a specified date within 10 days prior to the filing of this notice
(e)	Issuer's telephone number, including area code	(e)	Number of shares or other units of the class outstanding, or if debt securities the face amount thereof outstanding, as shown by the most recent report or statement published by the issuer
		(f)	Approximate date on which the securities are to be sold
2. (a)	Name of person for whose account the securities are to be sold	(g)	Name of each securities exchange, if any, on which the securities are intended to be sold
(b)	Such person's relationship to the issuer (e.g., officer, director, 10% stockholder, or member of immediate family of any of the foregoing)		
(c)	Such person's address, including zip code		

Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB control number.

SEC 1147 (08-07)

TABLE I — SECURITIES TO BE SOLD

Furnish the following information with respect to the acquisition of the securities to be sold and with respect to the payment of all or any part of the purchase price or other consideration therefor:

Title of the Class	Date you Acquired	Nature of Acquisition Transaction	Name of Person from Whom Acquired (If gift, also give date donor acquired)	Amount of Securities Acquired	Date of Payment	Nature of Payment
Common Stock	April 2017 - April 2018	Stock Awarded	Washington Trust Bancorp, Inc.	1,000	N/A	N/A

INSTRUCTIONS: If the securities were purchased and full payment therefor was not made in cash at the time of purchase, explain in the table or in a note thereto the nature of the consideration given. If the consideration consisted of any note or other obligation, or if payment was made in installments describe the arrangement and state when the note or other obligation was discharged in full or the last installment paid.

TABLE II — SECURITIES SOLD DURING THE PAST 3 MONTHS

Furnish the following information as to all securities of the issuer sold during the past 3 months by the person for whose account the securities are to be sold.

Name and Address of Seller	Title of Securities Sold	Date of Sale	Amount of Securities Sold	Gross Proceeds

None

REMARKS:

INSTRUCTIONS:

See the definition of "person" in paragraph (a) of Rule 144. Information is to be given not only as to the person for whose account the securities are to be sold but also as to all other persons included in that definition. In addition, information shall be given as to sales by all persons whose sales are required by paragraph (e) of Rule 144 to be aggregated with sales for the account of the person filing this notice.

ATTENTION:

The person for whose account the securities to which this notice relates are to be sold hereby represents by signing this notice that he does not know any material adverse information in regard to the current and prospective operations of the Issuer of the securities to be sold which has not been publicly disclosed. If such person has adopted a written trading plan or given trading instructions to satisfy Rule 10b5-1 under the Exchange Act, by signing the form and indicating the date that the plan was adopted or the instruction given, that person makes such representation as of the plan adoption or instruction date.

11/6/2018
DATE OF NOTICE

/s/ Kristen L. DiSanto, Attorney-in-Fact
(SIGNATURE)

DATE OF PLAN ADOPTION OR GIVING OF INSTRUCTION, IF RELYING ON RULE 10B5-1

The notice shall be signed by the person for whose account the securities are to be sold. At least one copy of the notice shall be manually signed. Any copies not manually signed shall bear typed or printed signatures.

ATTENTION: Intentional misstatements or omission of facts constitute Federal Criminal Violations (See 18 U.S.C. 1001)

SEC 1147 (02-08)

herit;font-size:8pt;font-weight:bold;">Liability
Method

Total

Equity
Method

Liability
Method

Total
Performance-based awards:

2010 awards
$
1,489

$
1,776

$
3,265

$
3,666

$
2,954

$
6,620

2011 awards
684

566

1,250

2,111

1,021

3,132

2012 awards
581

259

840

1,711

557

2,268

Retention awards
192

—

192

535

—

535

Total
$
2,946

$
2,601

$
5,547

$
8,023

$
4,532

$
12,555

Allocation of LTIP expense on our consolidated statements of income:
G&A expense

$
4,940

$
11,160

Operating expense

607

1,395

Total

$
5,547

$
12,555

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

	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

11. Distributions

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

Payment Date	Per Unit Cash Distribution Amount	Total Cash Distribution to Limited Partners
2/14/2012	$0.40750	$92,177
5/15/2012	0.42000	95,004
8/14/2012	0.47125	106,597
Through 9/30/2012	1.29875	293,778
11/14/2012	0.48500	109,707
Total	$1.78375	$403,485
2/14/2013	$0.50000	$113,340
5/15/2013	0.50750	115,040
8/14/2013	0.53250	120,707
Through 9/30/2013	1.54000	349,087
11/14/2013(1)	0.55750	126,374
Total	$2.09750	$475,461

(1) Our general partner's board of directors declared this cash distribution on October 24, 2013 to be paid on November 14, 2013 to unitholders of record at the close of business on November 7, 2013.

12. Fair Value

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:

- Cash and cash equivalents. Cash equivalents include money market and mutual fund accounts and commercial paper. The carrying amounts reported on our consolidated balance sheets approximate fair value due to the short-term maturity or variable rates of these instruments.

- Energy commodity derivatives deposits. This asset represents short-term deposits we have made associated with our energy commodity derivatives contracts. The carrying amount reported on our consolidated balance sheets approximates fair value as the deposits change daily in relation to the associated contracts and are held in separate accounts.

- Energy commodity derivatives contracts. These include NYMEX futures and exchange-traded butane futures agreements related to petroleum products. These contracts are carried at fair value on our consolidated balance sheets and are valued based on quoted prices in active markets. See Note 8 – Derivative Financial Instruments for further disclosures regarding these contracts.

- Treasury lock hedge derivative agreements. These agreements were entered into to protect against the risk of variability in interest payments related to a future debt issuance (see Note 8 – Derivative Financial Instruments for further disclosures regarding these agreements). Fair value was determined based on an assumed exchange, at the end of each period, in an orderly transaction with a market participant in the market in which the financial instrument is traded, adjusted for the effect of counter-party credit risk. The exchange value was calculated using present value techniques on estimated future cash flows based on forward interest rate curves.

- Long-term receivables. These are primarily insurance receivables, whose fair value was determined by estimating the present value of future cash flows using a risk-free rate of interest derived from U.S. treasury rates.

- Debt. The fair value of our publicly traded notes was based on the prices of those notes at December 31, 2012 and September 30, 2013; 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 approximates fair value due to the variable rates of that instrument.

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, 2012 and September 30, 2013, based on the three levels established by ASC 820-10-50; Fair Value Measurements and Disclosures—Overall—Disclosure. The carrying values of cash and cash equivalents (classified as Level 1) and energy commodity derivatives deposits approximate fair value because of the short-term nature or variable rates of these instruments; therefore, these items are not presented in the following tables.

As of December 31, 2012

Fair Value Measurements

Assets / (Liabilities) ($ in thousands)	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)	$(7,338)	$(7,338)	$(7,338)	$—	$—
Long-term receivables	$5,135	$5,108	$—	$—	$5,108
Debt	$(2,393,408)	$(2,721,985)	$(2,721,985)	$—	$—

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

	As of September 30, 2013				
			Fair Value Measurements		
Assets / (Liabilities) ($ in thousands)	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)	$9,407	$9,407	$9,407	$—	$—
Treasury lock hedge agreements	$(36)	$(36)	$—	$(36)	$—
Long-term receivables	$3,140	$3,097	$—	$—	$3,097
Debt	$(2,486,715)	$(2,676,025)	$—	$(2,676,025)	$—

During second quarter 2013, we reevaluated the market in which our debt securities trade. Based on that review, we determined that this market no longer included sufficient market activity to qualify as an active market, as defined in ASC 820, Fair Value Measurements. As a result, we transferred the hierarchical reporting level of the fair value measurement of our debt securities from Level 1 to Level 2. Our policy is to effect transfers between hierarchical reporting levels at the end of the reporting period where it has been determined that a change is required.

13. Related Party Transactions

Barry R. Pearl is an independent member of our general partner's board of directors and is also a director of Targa Resources Partners, L.P. ("Targa"). In the normal course of business, we purchase butane from subsidiaries of Targa. For the three months ended September 30, 2012 and 2013, we made purchases of butane from subsidiaries of Targa of less than $0.1 million and $1.0 million, respectively. For the nine months ended September 30, 2012 and 2013, we made purchases of butane from subsidiaries of Targa of $12.5 million and $15.6 million, respectively. These purchases were made on the same terms as comparable third-party transactions. We had $0.1 million and $0 payable to Targa at December 31, 2012 and September 30, 2013, respectively.

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

14. Subsequent Events

Recognizable events

No recognizable events occurred during the period.

Non-recognizable events

In October 2013, we issued $300.0 million of 5.15% notes due October 15, 2043 in an underwritten public offering. The notes were issued for the discounted price of 99.56% of par. We intend to use the net proceeds from this offering of approximately $295.6 million, after underwriting discounts and estimated offering expenses, to repay borrowings outstanding under our revolving credit facility and for general partnership purposes, which may include capital expenditures.

In September 2013, we entered into $150.0 million of Treasury lock contracts to protect against the risk of variability in future interest payments associated with the $300.0 million of notes discussed above (see Note 8 – Derivative Financial Instruments for more information on the Treasury lock contracts). In October 2013, we settled these Treasury lock contracts and realized a loss of $0.2 million. The loss was recorded to other comprehensive income and will be recognized into earnings as an adjustment to our periodic interest accruals over the next 30 years to coincide with interest payments on the underlying debt.

In October 2013, our general partner's board of directors declared a quarterly distribution of $0.5575 per unit to be paid on November 14, 2013 to unitholders of record at the close of business on November 7, 2013. The total cash distributions expected to be paid are $126.4 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, 2013, our three operating segments included:

- refined products segment, including almost 9,100 miles of refined products pipeline system with 49 connected terminals as well as 27 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;
- crude oil segment, comprised of approximately 800 miles of crude oil pipelines and storage facilities with an aggregate leasable storage capacity of approximately 15 million barrels; and
- marine storage segment, consisting of marine terminals located along coastal waterways with an aggregate storage capacity of more than 26 million barrels.

The following discussion provides an analysis of the results for each of our operating segments, an overview of our liquidity and capital resources and other items related to our partnership. The following discussion and analysis should be read in conjunction with (i) our accompanying interim consolidated financial statements and related notes, (ii) our consolidated financial statements, related notes and management's discussion and analysis of financial condition and results of operations included in our Annual Report on Form 10-K for the year ended December 31, 2012, and (iii) updates to the information contained in our Annual Report for the year ended December 31, 2012 related to the changes made in our reporting segments included in our Current Report on Form 8-K, which we filed with the Securities and Exchange Commission on April 29, 2013.

Recent Developments

Executive Officer Changes. Our Senior Vice President and Chief Financial Officer, John D. Chandler, has announced his resignation from such positions effective March 31, 2014.

2013 Debt Offering. In October 2013, we issued $300.0 million of 5.15% notes due October 15, 2043 in an underwritten public offering. The notes were issued for the discounted price of 99.56% of par. We intend to use the net proceeds from this offering of approximately $295.6 million, after underwriting discounts and estimated offering expenses, to repay borrowings outstanding under our revolving credit facility and for general partnership purposes, which may include capital expenditures.

In September 2013, we entered into $150.0 million of Treasury lock contracts to protect against the risk of variability in a portion of future interest payments associated with the $300.0 million of notes discussed above. In October 2013, we settled these Treasury lock contracts and realized a loss of $0.2 million. The loss was recorded to other comprehensive income and will be recognized into earnings as an adjustment to our periodic interest accruals over the next 30 years to coincide with interest payments on the underlying debt.

Longhorn Pipeline Reversal Project. In mid-April 2013, we began deliveries of crude oil from our Longhorn pipeline. During third quarter 2013, Longhorn's crude oil deliveries averaged approximately 100,000 barrels per day. The pipeline has been capable of operating at its full 225,000 barrel-per-day capacity since mid-October and is expected to average approximately 190,000 barrels per day during the fourth quarter. We plan to expand the capacity of the Longhorn pipeline by 50,000 barrels per day to 275,000 barrels per day, all fully committed by long-term contracts. Subject to regulatory approval, we expect to reach the 275,000 barrel-per-day operating capacity by mid-2014. We estimate this expansion project will cost approximately $55 million.

Pipeline Acquisition. In February 2013, we announced an agreement to acquire approximately 800 miles of refined petroleum products pipeline. On July 1, 2013, we closed on a portion of this transaction which includes a 250-mile pipeline that transports refined petroleum products from El Paso, Texas north to Albuquerque, New Mexico and transports products south to the U.S.-Mexico border for delivery within Mexico via a third-party pipeline. This New Mexico pipeline cost $57 million, which we funded with cash on hand. We expect to complete the remainder of this acquisition, which includes approximately 550 miles of common carrier pipeline that distributes refined petroleum products in Colorado, South Dakota and Wyoming in the fourth quarter of 2013 for an adjusted purchase price of $135 million. We expect to fund the remainder of this acquisition primarily with proceeds from our recent debt offering.

Cash Distribution. In October 2013, the board of directors of our general partner declared a quarterly cash distribution of $0.5575 per unit for the period of July 1, 2013 through September 30, 2013. This quarterly cash distribution will be paid on

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November 14, 2013 to unitholders of record on November 7, 2013. Total distributions expected to be paid under this declaration are approximately $126.4 million.

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

Results of Operations

We believe that investors benefit from having access to the same financial measures utilized by management. Operating margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. Operating margin is not a generally accepted accounting principles ("GAAP") measure, but the components of operating margin are computed using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the following tables. Operating profit includes expense items, such as depreciation and amortization expense and general and administrative ("G&A") expenses, which management does not focus on when evaluating the core profitability of our separate operating segments. Additionally, product margin, which management primarily uses to evaluate the profitability of our commodity-related activities, is provided in these tables. Product margin is a non-GAAP measure; however, its components of product sales and product purchases are determined in accordance with GAAP. 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 product purchases, better represents its importance to our results of operations.

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Three Months Ended September 30, 2012 Compared to Three Months Ended September 30, 2013

	Three Months Ended September 30,		Variance Favorable (Unfavorable)	
	2012	2013	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenue:				
Refined products	$193.8	$205.9	$12.1	6
Crude oil	23.9	49.5	25.6	107
Marine storage	37.8	39.9	2.1	6
Total transportation and terminals revenue	255.5	295.3	39.8	16
Affiliate management fee revenue	0.2	3.6	3.4	n/a
Operating expenses:				
Refined products	80.7	82.1	(1.4)	(2)
Crude oil	3.4	4.1	(0.7)	(21)
Marine storage	19.9	17.8	2.1	11
Intersegment eliminations	(0.7)	(0.8)	0.1	14
Total operating expenses	103.3	103.2	0.1	—
Product margin:				
Product sales revenue	70.2	144.9	74.7	106
Product purchases	85.8	120.3	(34.5)	(40)
Product margin(1)	(15.6)	24.6	40.2	n/a
Earnings of non-controlled entities	1.8	2.4	0.6	33
Operating margin	138.6	222.7	84.1	61
Depreciation and amortization expense	31.7	35.3	(3.6)	(11)
G&A expense	27.6	32.8	(5.2)	(19)
Operating profit	79.3	154.6	75.3	95
Interest expense (net of interest income and interest capitalized)	27.6	27.9	(0.3)	(1)
Debt placement fee amortization expense	0.6	0.5	0.1	17
Income before provision for income taxes	51.1	126.2	75.1	147
Provision for income taxes	0.5	0.6	(0.1)	(20)
Net income	$50.6	$125.6	$75.0	148
Operating Statistics:				
Refined products:				
Transportation revenue per barrel shipped	$1.228	$1.306		
Volume shipped (million barrels):				
Gasoline	61.8	61.9		
Distillates	36.5	36.1		
Aviation fuel	5.9	5.9		
Liquefied petroleum gases	3.2	4.0		
Total volume shipped	107.4	107.9		
Crude oil:				
Transportation revenue per barrel shipped	$0.311	$1.010		
Volume shipped (million barrels)	19.3	28.6		
Crude oil terminal average utilization (million barrels per month)	12.6	12.3		
Marine storage:				

Marine terminal average utilization (million barrels per month)	23.6	23.2

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

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Transportation and terminals revenue increased $39.8 million resulting from:

- an increase in refined products revenue of $12.1 million primarily due to revenue from the New Mexico pipeline we acquired on July 1, 2013, which represented approximately one-third of the increase, higher weighted average tariff rates on our existing pipeline system primarily due to our mid-year 2013 tariff rate increase of 4.6% and deficiency payments during third quarter 2013 from committed volumes that did not ship;
- an increase in crude oil revenue of $25.6 million primarily due to crude oil deliveries from our Longhorn pipeline, which represented approximately 90% of the increase, and additional condensate throughput at our Corpus Christi, Texas terminal. Our Longhorn pipeline began delivering crude oil in mid-April 2013 and averaged approximately 100,000 barrels per day during third quarter 2013; and
- an increase in marine storage revenue of $2.1 million primarily due to new storage placed into service at our Galena Park, Texas terminal since third-quarter 2012, as well as higher throughput fees.

Affiliate management fee revenue increased $3.4 million due to construction management fees we received in third quarter 2013 related to BridgeTex Pipeline Company, LLC ("BridgeTex") and management fees we received from operating storage tanks for Texas Frontera, LLC ("Texas Frontera"), both of which began after third quarter 2012.

Operating expenses decreased slightly by $0.1 million resulting from:

- an increase in refined products expenses of $1.4 million primarily due to expenses related to the New Mexico pipeline we acquired on July 1, 2013 and less favorable product gains (which reduce operating expenses), partially offset by lower environmental accruals and less asset retirements;
- an increase in crude oil expenses of $0.7 million primarily due to costs related to the operation of our Longhorn pipeline in crude oil service in the current period, including pipeline rental costs to access product from third-party origination sources, higher personnel costs, power and integrity spending, partially offset by more favorable product overages (which reduce operating expenses); and
- a decrease in marine storage expenses of $2.1 million primarily due to lower environmental accruals, partially offset by higher asset integrity costs and property taxes in the current period.

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. The period change in the mark-to-market value of these contracts that are not designated as hedges for accounting purposes, the effective portion of the change in value of matured NYMEX contracts that qualified for hedge accounting treatment and any ineffectiveness of NYMEX contracts that qualify for hedge accounting treatment are also included in product sales revenue. We use butane futures agreements to hedge against changes in the price of butane we expect to purchase in future periods. The period change in the mark-to-market value of these futures agreements, which were not designated as hedges, are included as adjustments to product purchases. Product margin increased $40.2 million primarily due to unrealized gains on NYMEX contracts in the current quarter compared to unrealized NYMEX losses in third quarter 2012, and higher margins from our butane blending activities as a result of higher volumes sold and lower butane costs. See Other Items—Commodity Derivative Agreements—Impact of Commodity Derivatives on Results of Operations below for more information about our NYMEX contracts.

Earnings of non-controlled entities increased $0.6 million primarily due to earnings of Double Eagle Pipeline LLC ("Double Eagle") and Texas Frontera, both of which began operations after third quarter 2012, partially offset by lower earnings of Osage Pipe Line Company, LLC ("Osage") primarily due to a lower weighted-average tariff rate.

Depreciation and amortization expense increased $3.6 million primarily due to expansion capital projects placed into service since third quarter 2012.

G&A expense increased $5.2 million primarily due to higher compensation costs resulting from an increase in employee headcount and an increase in the current year bonus accrual resulting from above-target payout estimates as well as legal costs associated with the pending refined products pipeline acquisition we expect to close in the fourth quarter of 2013.

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Nine Months Ended September 30, 2012 Compared to Nine Months Ended September 30, 2013

	Nine Months Ended September 30,		Variance Favorable (Unfavorable)	
	2012	2013	$ Change	% Change
Financial Highlights ($ in millions, except operating statistics)				
Transportation and terminals revenue:				
Refined products	$538.8	$573.6	$34.8	6
Crude oil	67.6	113.9	46.3	68
Marine storage	115.4	117.5	2.1	2
Total transportation and terminals revenue	721.8	805.0	83.2	12
Affiliate management fee revenue	0.6	10.6	10.0	n/a
Operating expenses:				
Refined products	204.1	194.9	9.2	5
Crude oil	4.0	13.2	(9.2)	(230)
Marine storage	48.1	40.0	8.1	17
Intersegment eliminations	(2.1)	(2.3)	0.2	10
Total operating expenses	254.1	245.8	8.3	3
Product margin:				
Product sales revenue	546.5	504.5	(42.0)	(8)
Product purchases	478.9	396.0	82.9	17
Product margin[(1)]	67.6	108.5	40.9	61
Earnings of non-controlled entities	4.9	5.2	0.3	6
Operating margin	540.8	683.5	142.7	26
Depreciation and amortization expense	94.7	105.8	(11.1)	(12)
G&A expense	76.7	96.1	(19.4)	(25)
Operating profit	369.4	481.6	112.2	30
Interest expense (net of interest income and interest capitalized)	83.9	84.6	(0.7)	(1)
Debt placement fee amortization expense	1.6	1.6	—	—
Income before provision for income taxes	283.9	395.4	111.5	39
Provision for income taxes	2.0	3.2	(1.2)	(60)
Net income	$281.9	$392.2	$110.3	39
Operating Statistics:				
Refined products:				
Transportation revenue per barrel shipped	$1.233	$1.274		
Volume shipped (million barrels):				
Gasoline	163.8	174.6		
Distillates	99.9	105.4		
Aviation fuel	16.7	15.4		
Liquefied petroleum gases	7.9	7.3		
Total volume shipped	288.3	302.7		
Crude oil:				
Transportation revenue per barrel shipped	$0.298	$0.765		
Volume shipped (million barrels)	51.4	72.6		
Crude oil terminal average utilization (million barrels per month)	12.6	12.4		
Marine storage:				
Marine terminal average utilization (million barrels per month)	23.8	22.9		

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

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Transportation and terminals revenue increased $83.2 million resulting from:

- an increase in refined products revenue of $34.8 million primarily due to a 5% increase in transportation volumes and higher rates. Gasoline and distillate shipments were higher primarily due to additional volumes on our South Texas pipeline system resulting from increased demand and incentive tariffs put in place to attract volumes, as well as volumes from the New Mexico pipeline we acquired on July 1, 2013, which contributed approximately 10% of the increase in transportation revenue. The average rate per barrel increased due to the mid-year 2012 and 2013 tariff rate increases of 8.6% and 4.6%, respectively, partially offset by more South Texas movements, which are at a significantly lower tariff rate than shipments on our other pipeline sections;
- an increase in crude oil revenue of $46.3 million primarily due to crude oil deliveries from our Longhorn pipeline, which represented approximately 80% of the increase, and higher utilization and rates on our Houston-area crude oil distribution system. Our Longhorn pipeline began delivering crude oil in 2013 and averaged approximately 95,000 barrels per day since its mid-April start date. We also benefited from additional condensate throughput at our Corpus Christi terminal; and
- an increase in marine storage revenue of $2.1 million primarily due to new storage placed into service at our Galena Park, Texas terminal since late 2012 and higher throughput fees.

Affiliate management fee revenue increased $10.0 million due to construction management fees we received in 2013 related to BridgeTex and management fees we received from operating storage tanks for Texas Frontera, both of which began after the third quarter of 2012.

Operating expenses decreased $8.3 million resulting from:

- a decrease in refined products expenses of $9.2 million primarily due to higher product overages (which reduce operating expenses), favorable gains on asset sales and lower losses on asset retirements, the 2013 favorable adjustment of an accrual for air emission fees at our East Houston terminal (see Notes to Consolidated Financial Statements, Note 9—Commitments and Contingencies for more information regarding the adjustment of this accrual) and lower environmental accruals, partially offset by higher compensation, power costs and property taxes, as well as expenses related to the New Mexico pipeline we acquired on July 1, 2013. The higher compensation costs were due to increased employee headcount and higher bonus accruals. The higher power costs primarily reflect the increase in product shipments over 2012 and the higher property taxes are the result of asset additions over the past year;
- an increase in crude oil expenses of $9.2 million primarily due to costs related to the operation of our Longhorn pipeline in crude oil service in the 2013, including pipeline rental costs to access product from third-party origination sources, higher personnel costs, power and integrity spending, partially offset by more favorable product overages (which reduce operating expenses); and
- a decrease in marine storage expenses of $8.1 million primarily due to the 2013 favorable adjustment of an accrual for potential air emission fees at our Galena Park, Texas facility (see Notes to Consolidated Financial Statements, Note 9—Commitments and Contingencies for more information regarding the adjustment of this accrual) and lower environmental accruals, partially offset by insurance reimbursements received in 2012 for historical hurricane-related damage and higher asset integrity costs in 2013.

Product margin increased $40.9 million primarily due to unrealized gains on NYMEX contracts in the current year compared to unrealized NYMEX losses in 2012, and higher margins from our butane blending activities mainly as a result of lower butane costs. See Other Items—Commodity Derivative Agreements—Impact of Commodity Derivatives on Results of Operations below for more information about our NYMEX contracts.

Earnings of non-controlled entities increased $0.3 million primarily due to earnings of Double Eagle and Texas Frontera, both of which began operations after third quarter 2012, partially offset by lower earnings of Osage.

Depreciation and amortization expense increased $11.1 million primarily due to increased amortization of intangible assets and expansion capital projects placed into service since 2012.

G&A expense increased $19.4 million primarily due to higher compensation costs resulting from an increase in employee headcount and an increase in the current year bonus accrual resulting from above-target payout estimates, legal costs related to potential projects and the pending acquisition we expect to close in the fourth quarter of 2013, and higher equity-based compensation costs and deferred board of director compensation expense primarily due to a higher price for our limited partner units.

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Distributable Cash Flow

Distributable cash flow ("DCF") and adjusted EBITDA are non-GAAP measures. Management uses this measure as a basis for recommending to our general partner's board of directors the amount of cash distributions to be paid each period. Management also uses DCF (adjusted) as a performance measure in determining equity-based compensation and also to evaluate our ability to generate cash for distribution to our limited partners. 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, 2012 and 2013 to net income, which is its nearest comparable GAAP financial measure, follows (in millions):

	Nine Months Ended September 30,		Increase
	2012	2013	(Decrease)
Net income	$281.9	$392.2	$110.3
Interest expense, net	83.9	84.6	0.7
Depreciation and amortization(1)	96.2	107.4	11.2
Equity-based incentive compensation expense(2)	(0.4)	2.2	2.6
Asset retirements and impairments	10.6	4.3	(6.3)
Commodity-related adjustments:			
Derivative (gains) losses recognized in the period associated with future product transactions(3)	18.4	(8.3)	(26.7)
Derivative gains (losses) recognized in previous periods associated with products sold in the period(4)	(6.7)	(5.7)	1.0
Lower-of-cost-or-market adjustments	(1.0)	(0.5)	0.5
Houston-to-El Paso cost of sales adjustments(5)	8.2	—	(8.2)
Total commodity-related adjustments	18.9	(14.5)	(33.4)
Other	0.4	(3.0)	(3.4)
Adjusted EBITDA	491.5	573.2	81.7
Interest expense, net	(83.9)	(84.6)	(0.7)
Maintenance capital(6)	(47.2)	(55.5)	(8.3)
DCF	$360.4	$433.1	$72.7

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

(2) Because we intend to satisfy vesting of units under our equity-based incentive compensation program with the issuance of limited partner units, expenses related to this program generally are deemed non-cash and added back for DCF purposes. Total equity-based incentive compensation expense for the nine months ended September 30, 2012 and 2013 was $12.6 million and $14.5 million, respectively. However, the figures above include an adjustment for minimum statutory tax withholdings we paid in 2012 and 2013 of $13.0 million and $12.3 million, respectively, for equity-based incentive compensation units that vested at the previous year end, which reduce 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) Cost of goods sold adjustment related to commodity activities for our Houston-to-El Paso pipeline to more closely resemble current market prices for the applicable period for DCF purposes rather than average inventory costing as used to determine our results of operations. We discontinued these commodity activities during 2012 in conjunction with the Longhorn crude pipeline project.

(6) Maintenance capital expenditure projects are not undertaken primarily to 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.

Current period DCF increased $72.7 million over the prior year. The change in net income and depreciation and amortization is discussed in detail in Results of Operations above, the change in equity-based compensation is discussed in footnote 2 to the table above and a discussion of our maintenance capital expenditures is provided in Capital Requirements below. The change in DCF from commodity-related adjustments is primarily due to the impact of product price changes during

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each period on economic hedges that do not qualify for hedge accounting treatment and the discontinuance of our Houston-to-El Paso linefill management activities.

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

	For the Nine Months Ended September 30,	
	2012	2013
Distributable cash flow	$360.4	$433.1
Less: Cash reserves approved by our general partner	66.6	84.0
Total cash distributions paid	$293.8	$349.1

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Net cash provided by operating activities was $412.2 million and $521.2 million for the nine months ended September 30, 2012 and 2013, respectively. The $109.0 million increase from 2012 to 2013 was primarily attributable to:

- a $121.4 million increase in net income, excluding the increase in non-cash depreciation and amortization expense;
- a $16.4 million increase resulting from a $21.5 million increase in deferred revenue in 2013 versus a $5.1 million increase in deferred revenue in 2012. 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 has future make-up rights and a deferral of a sale of an asset where the title has not yet passed, but the cash has been received. The decrease in 2012 was primarily due to a customer deficiency recognized in 2011 due to the make-up period expiring (with no like amount in 2012);
- a $15.8 million increase resulting from a $1.0 million increase in accounts payable in 2013 versus a $14.8 million decrease in accounts payable in 2012, primarily due to the timing of invoices paid to vendors and suppliers; and
- an $11.5 million increase resulting from an $11.1 million increase in trade accounts receivable and other accounts receivable in 2013 versus a $22.6 million increase during 2012, primarily due to timing of payments from our customers.

These increases were partially offset by:

- a $24.7 million decrease resulting from a $13.4 million decrease in inventory in 2013 versus a $38.1 million decrease in inventory in 2012. The decrease in 2012 was primarily due to the sale of our Houston-to-El Paso pipeline section linefill working inventory in anticipation of converting that pipeline to crude oil service;
- a $15.9 million decrease resulting from an $8.9 million decrease in energy commodity derivatives contracts, net of derivatives deposits in 2013, versus a $7.0 million increase in 2012, primarily due to the impact of changes in commodity prices on our economic hedges and a decrease in the number of NYMEX contracts during 2012;
- a $13.0 million decrease resulting from a $2.3 million decrease in accrued product purchases in 2013 versus a $10.7 million increase in accrued product purchases in 2012, primarily due to the timing of invoices paid to vendors and suppliers; and
- a $12.8 million decrease resulting from a $10.8 million decrease in current and noncurrent environmental liabilities in 2013 versus a $2.0 million increase in current and noncurrent environmental liabilities in 2012, primarily due to an adjustment during the current period of an accrual for potential air emission fees at our East Houston terminal and Galena Park facilities (see Environmental below for more information regarding the adjustment of this accrual).

Net cash used by investing activities for the nine months ended September 30, 2012 and 2013 was $220.8 million and $577.3 million, respectively. 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. Our expansion capital spending during 2013 was primarily for the Longhorn pipeline reversal project. Also during 2013, we contributed capital of $181.4 million in conjunction with our

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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. During 2012, we spent $230.0 million for capital expenditures, which included $47.2 million for maintenance capital and $182.8 million for expansion capital, and contributed capital of $37.5 million in conjunction with our joint venture capital projects.

Net cash used by financing activities for the nine months ended September 30, 2012 and 2013 was $300.5 million and $258.0 million, respectively. During the first nine months of 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 participants, resulting in payments of associated tax withholdings of $12.3 million. During the first nine months of 2012, we paid cash distributions of $293.8 million to our unitholders. Also, in January 2012, the cumulative amounts of the January 2009 equity-based incentive compensation award grants were settled by issuing 722,766 limited partner units and distributing those units to the participants, resulting in payments of associated tax withholdings of $13.0 million.

The quarterly distribution amount related to our third-quarter 2013 financial results (to be paid in fourth quarter 2013) is $0.5575 per unit. If we meet management's targeted distribution growth of 16% for 2013 and the number of outstanding limited partner units remains at 226.7 million, total cash distributions of approximately $494.2 million will be paid to our unitholders related to 2013 financial results. Management believes we will have sufficient distributable cash flow to fund these distributions.

Capital Requirements

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

- Maintenance capital expenditures. 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, 2012 and 2013, our maintenance capital spending was $47.2 million and $55.5 million, respectively. For 2013, we expect to incur maintenance capital expenditures for our existing businesses of approximately $75.0 million.

During the first nine months of 2013, we spent $234.2 million for organic growth capital and $181.4 million for capital projects in conjunction with our joint ventures. Additionally, we spent $79.5 million on acquisitions. Based on the progress of expansion projects already underway, including the reversal and conversion of our Longhorn pipeline from refined products to crude oil service and our investment in the BridgeTex pipeline, we expect to spend approximately $925 million for expansion capital during 2013, which includes $192 million for the New Mexico pipeline we acquired on July 1, 2013 and the pending acquisition of the Rocky Mountain pipeline, with an additional $400 million in 2014 to complete our current projects.

Liquidity

Consolidated debt at December 31, 2012 and September 30, 2013 was as follows (in millions):

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	December 31, 2012	September 30, 2013	Weighted-Average Interest Rate at September 30, 2013 (1)
Revolving credit facility	$—	$98.4	1.2%
$250.0 of 6.45% Notes due 2014	249.9	250.0	6.3%
$250.0 of 5.65% Notes due 2016	251.6	251.3	5.7%
$250.0 of 6.40% Notes due 2018	261.4	259.9	5.4%
$550.0 of 6.55% Notes due 2019	575.1	572.4	5.7%
$550.0 of 4.25% Notes due 2021	558.1	557.4	4.0%
$250.0 of 6.40% Notes due 2037	249.0	249.0	6.4%
$250.0 of 4.20% Notes due 2042	248.3	248.4	4.2%
Total debt	$2,393.4	$2,486.8	5.2%

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

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

The face value of our debt at December 31, 2012 and September 30, 2013 was $2.4 billion. The difference between the face value and carrying value of the debt outstanding is the unamortized portion of various fair value hedges and the unamortized discounts and premiums on debt issuances. Realized gains and losses on fair value hedges and note discounts and premiums are being amortized or accreted to the applicable notes over the respective lives of those notes.

6.45% Notes due 2014. The maturity date of our $250.0 million of 6.45% notes is June 1, 2014. The carrying amount of these notes was recorded as current portion of long-term debt on our consolidated balance sheet as of September 30, 2013. We anticipate refinancing this debt prior to its maturity in June 2014.

Revolving Credit Facility. The total borrowing capacity under our revolving credit facility, which matures in October 2016, is $800.0 million. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 0.875% to 1.75% based on our credit ratings and amounts outstanding under the facility. Additionally, an unused commitment fee is assessed at a rate from 0.125% to 0.3%, depending on our credit ratings. The unused commitment fee was 0.2% at September 30, 2013. Borrowings under this facility may be used for general purposes, including capital expenditures. As of September 30, 2013, there was $98.4 million 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.

Interest Rate Derivatives. In September 2013, we entered into $150.0 million of Treasury lock contracts to hedge against the risk of variability of future interest payments on a portion of the debt we expected to issue in early October 2013. The fair value of these contracts at September 30, 2013 was a liability of less than $0.1 million. These contracts were settled on October 3, 2013 for a loss of $0.2 million. We have accounted for these contracts as cash flow hedges.

See Recent Developments above for a discussion of the debt we issued after September 30, 2013.

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.

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Clean Air Act - Section 185 Liability

Section 185 of the Clean Air Act ("CAA 185") requires states to collect annual fees from major source facilities located in severe or extreme nonattainment ozone areas that did not meet the attainment deadline. The CAA 185 fees are required annually until the area is redesignated as an attainment area for ozone. The Environmental Protection Agency ("EPA") is required to collect the fees if a state does not administer and enforce CAA 185. The Houston-Galveston region was initially determined to be a severe nonattainment area that did not meet its 2007 attainment deadline and, as such, would be subject to CAA 185. In June 2013, the Texas Commission on Environmental Quality ("TCEQ") adopted its "Failure to Attain Rule" to implement the requirements of CAA 185 which will provide for the collection of an annual failure to attain fee for excess emissions but does not require retroactive assessment of Section 185 fees for the annual periods of 2008 through 2011. As a result, we reduced our accrual and decreased our environmental expense by $10.6 million in the second quarter of 2013 in accordance with the TCEQ's final rule. The total remaining accrual as of September 30, 2013 is $0.7 million.

Other Items

Commodity Derivative Agreements. Certain of the business activities in which we engage result in our owning various commodities which exposes us to commodity price risk. We use NYMEX contracts and butane futures agreements to help manage this commodity price risk. We use NYMEX contracts to hedge against changes in the price of refined products we expect to sell in future periods. We use and account for those NYMEX contracts that qualify for hedge accounting treatment as either cash flow or fair value hedges, and we use and account for those NYMEX contracts that do not qualify for hedge accounting treatment as economic hedges. We use butane futures agreements to economically hedge against changes in the price of butane we expect to purchase in the future as part of our butane blending activity. As of September 30, 2013, our open derivative contracts were as follows:

Open Derivative Contracts Designated as Hedges

- NYMEX contracts covering 0.7 million barrels of crude oil to hedge against future price changes of crude oil linefill and tank bottom inventory. These contracts, which we are accounting for as fair value hedges, mature between October 2013 and November 2016. Through September 30, 2013, the cumulative amount of losses from these agreements was $10.2 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 2.8 million barrels of refined products related to our butane blending and fractionation activities. These contracts mature between October 2013 and April 2014 and are being accounted for as economic hedges. Through September 30, 2013, the cumulative amount of net unrealized gains associated with these agreements was $5.0 million, all of which was recognized as an increase to product sales in 2013.

- NYMEX contracts covering 0.4 million barrels of refined products and crude oil related to inventory we carry that resulted from pipeline product overages. These contracts, which mature in October 2013, are being accounted for as economic hedges. Through September 30, 2013, the cumulative amount of net unrealized gains associated with these agreements was $0.5 million. We recorded these gains as a decrease in operating expenses, all of which was recognized in 2013.

- Butane futures agreements to purchase 0.4 million barrels of butane that mature between October 2013 and April 2014, which are being accounted for as economic hedges. Through September 30, 2013, the cumulative amount of net unrealized gains associated with these agreements was $2.7 million. We recorded these gains as a decrease in product purchases, all of which was recognized in 2013.

Settled Derivative Contracts

- We settled NYMEX contracts covering 5.1 million barrels of refined products related to economic hedges of products from our butane blending and fractionation activities that we sold during 2013. We recognized a gain of $3.5 million in 2013 related to these contracts which we recorded as an adjustment to product sales revenue.

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- We settled NYMEX contracts covering 0.2 million barrels of refined products related to cash flow hedges of products from our butane blending and fractionation activities that we sold during 2013. We recognized a loss of $4.4 million on the settlement of these contracts which we recorded as an adjustment to product sales revenue.

- We settled NYMEX contracts covering 3.9 million barrels of refined products and crude oil related to economic hedges of product inventories from product overages on our pipeline system which we sold during 2013. We recognized a loss of $2.1 million in 2013 on the settlement of these contracts which we recorded as an adjustment to operating expense.

- We settled butane futures agreements covering 0.2 million barrels related to economic hedges of butane purchases we made during 2013 associated with our butane blending activities. We recognized a loss of $0.6 million in the current period on the settlement of these contracts which we recorded as an adjustment to product purchases.

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 contracts on our results of operations for the respective periods presented (in millions):

	Nine Months Ended September 30, 2012			
	Product Sales	Product Purchases	Operating Expense	Net Impact on Results of Operations
NYMEX losses recognized during the period that were associated with economic hedges of physical product sales or purchases during the period	$(27.6)	$(0.5)	$(2.4)	$(30.5)
NYMEX losses recorded during the period that were associated with products that will be or were sold or purchased in future periods	(10.5)	(1.1)	(0.8)	(12.4)
Net impact of NYMEX contracts	$(38.1)	$(1.6)	$(3.2)	$(42.9)

	Nine Months Ended September 30, 2013			
	Product Sales	Product Purchases	Operating Expense	Net Impact on Results of Operations
NYMEX losses recognized during the period that were associated with economic hedges of physical product sales or purchases during the period	$(0.9)	$(0.6)	$(2.1)	$(3.6)
NYMEX 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 contracts	$4.1	$2.1	$(1.6)	$4.6

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, 2012 and 2013, we made purchases of butane from subsidiaries of Targa of less than $0.1 million and $1.0 million, respectively. For the nine months ended September 30, 2012 and 2013, we made purchases of butane from subsidiaries of Targa of $12.5 million and $15.6 million, respectively. These purchases were made on the same terms as comparable third-party transactions. We had $0.1 million and $0 payable to Targa at December 31, 2012 and September 30, 2013, respectively.

We own a 50% interest in Texas Frontera, which owns 0.8 million barrels of refined products storage at our Galena Park, Texas terminal. The storage capacity owned by this venture is leased to an affiliate of Texas Frontera under a long-term lease agreement. Texas Frontera began operations in October 2012. 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 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 owns a 140-mile pipeline that connects to an existing pipeline owned by an affiliate of Double Eagle. Double Eagle is operated by a third-party entity. This pipeline, which began limited operation in

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second quarter 2013, transports condensate from the Eagle Ford shale formation to our terminal in Corpus Christi, Texas. We receive connection fees from Double Eagle that are included in our transportation and terminals revenue on our consolidated statements of income. For the three and nine months ended September 30, 2013, we received connection fees of $0.5 million and $0.8 million, respectively, and we recorded a $0.2 million trade accounts receivable from Double Eagle at September 30, 2013.

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

New Accounting Pronouncements

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

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

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We may be exposed to market risk through changes in commodity prices and interest rates. We have established policies to monitor and control these market risks. We also enter into derivative agreements to help manage our exposure to commodity price and interest rate risks.

Commodity Price Risk

We use derivatives to help us manage commodity price risk. Forward physical contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting. As of September 30, 2013, we had commitments under forward purchase and sale contracts used in our butane blending and fractionation activities as follows (in millions):

	Market Value	Barrels
Forward purchase contracts	$158.8	2.6
Forward sale contracts	$44.4	0.4

We use NYMEX contracts to hedge against changes in the price of petroleum products we expect to sell from activities in which we acquire or produce petroleum products. Some of these NYMEX contracts qualify for hedge accounting treatment, and we designate and account for these as either cash flow or fair value hedges. We account for those NYMEX contracts that do not qualify for hedge accounting treatment, or are otherwise undesignated as cash flow or fair value hedges, as economic hedges. We also use butane futures agreements to hedge against changes in the price of butane that we expect to purchase in future periods. At September 30, 2013, we had open NYMEX contracts representing 3.9 million barrels of petroleum products we expect to sell in the future. Additionally, we had open butane futures agreements for 0.4 million barrels of butane we expect to purchase in the future.

At September 30, 2013, the fair value of our open NYMEX contracts was an asset of $6.7 million and the fair value of our butane futures agreements was an asset of $2.7 million. Combined, the net asset of $9.4 million was recorded as a current asset to energy commodity derivatives contracts ($8.4 million) and other non-current assets ($1.0 million).

At September 30, 2013, open NYMEX contracts representing 3.2 million barrels of petroleum products did not qualify for hedge accounting treatment. A $10.00 per barrel increase in the price of these NYMEX contracts for reformulated gasoline blendstock for oxygen blending ("RBOB") gasoline or heating oil would result in a $32.0 million decrease in our operating profit and a $10.00 per barrel decrease in the price of these NYMEX contracts for RBOB or heating oil would result in a $32.0 million increase in our operating profit. However, the increases or decreases in operating profit we recognize from our open NYMEX contracts will be substantially offset by higher or lower product sales revenue when the physical sale of the product occurs. These contracts may be for the purchase or sale of product in markets different from those in which we are attempting to hedge our exposure, resulting in hedges that do not eliminate all price risks.

Interest Rate Risk

At September 30, 2013, we had $98.4 million outstanding on our variable rate revolving credit facility. Considering the amount outstanding on our revolving credit facility as of September 30, 2013, our annual interest expense would change by $0.1 million if LIBOR were to change by 0.125%.

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

ITEM 4. CONTROLS AND PROCEDURES

We performed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in rule 13a-14(c) of the Securities Exchange Act) as of the end of the period covered by the date of this report. We performed this evaluation under the supervision and with the participation of our management, including our general partner's Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our general partner's Chief Executive Officer

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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, 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Forward-Looking Statements

Certain matters discussed in this Quarterly Report on Form 10-Q include forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act that discuss our expected future results based on current and pending business operations. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as "anticipates," "believes," "continue," "could," "estimates," "expects," "forecasts," "goal," "guidance," "intends," "may," "might," "plans," "potential," "projects," "scheduled," "should" and other similar expressions. Although we believe our forward-looking statements are based on reasonable assumptions, statements made regarding future results are not guarantees of future performance and subject to numerous assumptions, uncertainties and risks that are difficult to predict. Therefore, actual outcomes and results may be materially different from the results stated or implied in such forward-looking statements included in this report.

The following are among the important factors that could cause future results to differ materially from any projected, forecasted, estimated or budgeted amounts we have discussed in this report:

- overall demand for refined products, crude oil, liquefied petroleum gases and ammonia in the U.S.;
- price fluctuations for refined products, crude oil, liquefied petroleum gases and ammonia and expectations about future prices for these products;
- changes in general economic conditions, interest rates and price levels;
- changes in the financial condition of our customers, vendors, derivatives counterparties, joint venture co-owners or lenders;
- our ability to secure financing in the credit and capital markets in amounts and on terms that will allow us to execute our growth strategy, refinance our existing obligations when due and maintain adequate liquidity;
- development of alternative energy sources, including but not limited to natural gas, solar power, wind power and geothermal energy, increased use of biofuels such as ethanol and biodiesel, increased conservation or fuel efficiency, as well as regulatory developments or other trends that could affect demand for our services;
- changes in the throughput or interruption in service on refined products or crude oil pipelines owned and operated by third parties and connected to our assets;
- changes in demand for storage in our refined products or crude oil terminals;
- changes in supply patterns for our storage terminals due to geopolitical events;
- our ability to manage interest rate and commodity price exposures;
- changes in our tariff rates implemented by the Federal Energy Regulatory Commission, the U.S. Surface Transportation Board or state regulatory agencies;
- shut-downs or cutbacks at refineries, oil wells, petrochemical plants, ammonia production facilities or other customers or businesses that use or supply our services;
- the effect of weather patterns and other natural phenomena, including climate change, on our operations and demand for our services;
- an increase in the competition our operations encounter;

- the occurrence of natural disasters, terrorism, operational hazards, equipment failures, system failures or unforeseen interruptions for which we are not adequately insured;
- the treatment of us as a corporation for federal or state income tax purposes or if we become subject to significant forms of other taxation or more aggressive enforcement or increased assessments under existing forms of taxation;
- our ability to identify expansion projects or to complete identified expansion projects on time and at projected costs;
- our ability to make and integrate accretive acquisitions and joint ventures and successfully execute our business strategy;
- uncertainty of estimates, including accruals and costs of environmental remediation;
- our ability to cooperate with and rely on our joint venture co-owners;
- actions by rating agencies concerning our credit ratings;

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- our ability to timely obtain and maintain all necessary approvals, consents and permits required to operate our existing assets and any new or modified assets;
- our ability to promptly obtain all necessary materials, labor, supplies and rights-of-way required for construction of our growth projects, and to complete construction without significant delays, disputes or cost overruns;
- risks inherent in the use and security of information systems in our business and implementation of new software and hardware;
- changes in laws and regulations that govern product quality specifications that could impact our ability to produce gasoline volumes through our blending activities or that could require significant capital outlays for compliance;
- changes in laws and regulations to which we or our customers are or become subject, including tax withholding issues, safety, security, employment and environmental laws and regulations, including laws and regulations designed to address climate change and laws and regulations affecting hydraulic fracturing;
- the cost and effects of legal and administrative claims and proceedings against us or our subsidiaries;
- the amount of our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- the effect of changes in accounting policies;
- the potential that our internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful;
- the ability of third parties to perform on their contractual obligations to us;
- petroleum product supply disruptions;
- global and domestic repercussions from terrorist activities, including cyber attacks, and the government's response thereto; and
- other factors and uncertainties inherent in the transportation, storage and distribution of refined products and crude oil.

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

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PART II
OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In February 2010, a class action lawsuit was filed against us, ARCO Midcon L.L.C. and WilTel Communications, L.L.C. (“WilTel”). The complaint alleges that the property owned by plaintiffs and those similarly situated has been damaged by the existence of hazardous chemicals migrating from a pipeline easement onto the plaintiffs' property. We acquired the pipeline from ARCO Pipeline (“APL”) in 1994 as part of a larger transaction and subsequently transferred the property to WilTel. We are required to indemnify and defend WilTel pursuant to the transfer agreement. Prior to our acquisition of the pipeline from APL, the pipeline was purged of product. Neither we nor WilTel ever transported hazardous materials through the pipeline. A hearing on the plaintiffs' Motion for Class Certification was held in the U.S. District Court for the Eastern District of Missouri in December 2012. The court has not yet rendered a decision on the issue of class certification. We believe that the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

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 believe that the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

In March 2012, we received a Notice of Probable Violation from the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration ("PHMSA") for alleged violations related to the operation and maintenance of certain pipelines in Oklahoma and Texas. We have accrued approximately $0.1 million for potential monetary sanctions related to this matter. We believe that the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

In April 2012, we received an information request from the EPA pursuant to Section 308 of the Clean Water Act, regarding a pipeline release in December 2011 in Nebraska. We have accrued $0.6 million for potential monetary sanctions related to this matter. We believe that the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

We have liability at the U.S. Oil Recovery Superfund Site in Pasadena, Texas as a potential responsible party under Section 107(a) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended. Currently, there is an ongoing removal action designed to stabilize the site, remove the immediate threat posed at the site and set the stage for a later more comprehensive action, known as the assessment phase. We have accrued and 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.

In April 2013, we received a Notice of Probable Violation from PHMSA, which resulted from alleged violations discovered during a 2012 inspection of our central Oklahoma pipeline facilities. In third quarter 2013, we paid $0.1 million for monetary sanctions related to this matter, which is now resolved.

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, 2012, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not our only risks. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

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

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

The Energy Independence and Security Act of 2007 expanded the required use of renewable fuels in the United States. Each year, the EPA establishes a Renewable Volume Obligation ("RVO") requirement for refiners and fuel manufacturers based on overall quotas established by the federal government. By virtue of our butane blending activity, and resulting gasoline production, we are an obligated party and receive an annual RVO from the EPA. In lieu of blending renewable fuels (such as ethanol and biodiesel), we have the option to purchase renewable energy credits, called RINs, to meet this obligation. RINs are generated when a gallon of biofuel such as ethanol or biodiesel is produced. RINs may be separated when the biofuel is blended into gasoline or diesel, at which point the RIN is available for use in compliance or is available for sale on the open market. The cost of RINs has been volatile during 2013, and the cost and availability of RINs could have an adverse impact on our results of operations, cash flows and cash distributions.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

None.

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ITEM 6. EXHIBITS

Exhibit Number		Description
Exhibit 12	—	Ratio of earnings to fixed charges.
Exhibit 31.1	—	Certification of Michael N. Mears, principal executive officer.
Exhibit 31.2	—	Certification of John D. Chandler, principal financial officer.
Exhibit 32.1	—	Section 1350 Certification of Michael N. Mears, Chief Executive Officer.
Exhibit 32.2	—	Section 1350 Certification of John D. Chandler, Chief Financial Officer.
Exhibit 101.INS	—	XBRL Instance Document.
Exhibit 101.SCH	—	XBRL Taxonomy Extension Schema.
Exhibit 101.CAL	—	XBRL Taxonomy Extension Calculation Linkbase.
Exhibit 101.DEF	—	XBRL Taxonomy Extension Definition Linkbase.
Exhibit 101.LAB	—	XBRL Taxonomy Extension Label Linkbase.
Exhibit 101.PRE	—	XBRL Taxonomy Extension Presentation Linkbase.

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SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized in Tulsa, Oklahoma on November 1, 2013.

MAGELLAN MIDSTREAM PARTNERS, L.P.

By: Magellan GP, LLC,
its general partner

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

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