Tallgrass Energy Partners, LP
Form 10-Q
August 03, 2016

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

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended June 30, 2016
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number 001-35917

Tallgrass Energy Partners, LP
(Exact name of registrant as specified in its charter)

Delaware	46-1972941
(State or other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification Number)
4200 W. 115th Street, Suite 350	
Leawood, Kansas	66211
(Address of Principal Executive Offices)	(Zip Code)

(913) 928-6060
(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. See the definitions of "large accelerated filer", "accelerated filer", and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	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
On August 3, 2016, the Registrant had 72,108,934 Common Units and 834,391 General Partner Units outstanding.

TALLGRASS ENERGY PARTNERS, LP
TABLE OF CONTENTS

Glossary of Common Industry and Measurement Terms

Bakken oil production area: Montana and North Dakota in the United States and Saskatchewan and Manitoba in Canada.

Barrel (or bbl): forty two U.S. gallons.

Base Gas (or Cushion Gas): the volume of gas that is intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates.

BBtu: one billion British Thermal Units.

Bcf: one billion cubic feet.

British Thermal Units or Btus: the amount of heat energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

Commodity sensitive contracts or arrangements: contracts or other arrangements, including tariff provisions, that directly expose our cash flows to increases and decreases in the price of commodities such as crude oil, natural gas and NGLs. Examples are Keep Whole Processing Contracts and Percent of Proceeds Processing Contracts, as well as pipeline loss allowances on our pipelines.

Condensate: a NGL with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions.

Contract barrels: barrels of crude oil that our customers have contractually agreed to ship in exchange for firm service assurance of capacity and deliverability to delivery points.

Delivery point: any point at which product in a pipeline is delivered to or for the account of a customer.

Dry gas: a gas primarily composed of methane and ethane where heavy hydrocarbons and water either do not exist or have been removed through processing.

Dth: a dekatherm, which is a unit of energy equal to 10 therms or one million British thermal units.

End-user markets: the ultimate users and consumers of transported energy products.

EPA: the United States Environmental Protection Agency.

FERC: Federal Energy Regulatory Commission.

Firm fee contracts: firm fee contracts generally obligate our customers to pay a fixed recurring charge to reserve an agreed upon amount of capacity and/or deliverability on our assets, regardless if the contracted capacity is actually used by the customer. Such contracts are also commonly known as "take-or-pay" contracts.

Firm services: services pursuant to which customers receive firm assurances regarding the availability of capacity and/or deliverability of natural gas, crude oil or other hydrocarbons or water on our assets up to a contracted amount.

Fractionation: the process by which NGLs are further separated into individual, typically more valuable components including ethane, propane, butane, isobutane and natural gasoline.

GAAP: generally accepted accounting principles in the United States of America.

GHGs: greenhouse gases.

Header system: networks of medium-to-large-diameter high pressure pipelines that connect local gathering systems to large diameter high pressure long-haul transportation pipelines.

Interruptible services: services pursuant to which customers receive limited, or no, assurances regarding the availability of capacity and deliverability in our assets.

Keep Whole Processing Contracts: natural gas processing contracts in which we are required to replace the Btu content of the NGLs extracted from inlet wet gas processed with purchased dry natural gas.

Line fill: the volume of oil, in barrels, in the pipeline from the origin to the destination.

Liquefied natural gas or LNG: natural gas that has been cooled to minus 161 degrees Celsius for transportation, typically by ship. The cooling process reduces the volume of natural gas by 600 times.
Local distribution company or LDC: LDCs are involved in the delivery of natural gas to consumers within a specific geographic area.
Long-term: with respect to any contract, a contract with an initial duration greater than one year.
MMBtu: one million British Thermal Units.
Mcf: one thousand cubic feet.
MMcf: one million cubic feet.
Natural gas liquids or NGLs: those hydrocarbons in natural gas that are separated from the natural gas as liquids through the process of absorption, condensation, adsorption or other methods in natural gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as lease condensate, natural gasoline and liquefied petroleum gases. Natural gas liquids include natural gas plant liquids (primarily ethane, propane, butane and isobutane) and lease condensate (primarily pentanes produced from natural gas at lease separators and field facilities).
Natural Gas Processing: the separation of natural gas into pipeline-quality natural gas and a mixed NGL stream.
Non-contract barrels (or walk-up barrels): barrels of crude oil that our customers ship based solely on availability of capacity and deliverability with no assurance of future capacity.
No-notice service: those services pursuant to which customers receive the right to transport or store natural gas on assets outside of the daily nomination cycle without incurring penalties.
NYMEX: New York Mercantile Exchange.
Park and loan services: those services pursuant to which customers receive the right to store natural gas in (park), or borrow gas from (loan), our facilities on a seasonal basis.
Percent of Proceeds Processing Contracts: natural gas processing contracts in which we process our customer's natural gas, sell the resulting NGLs and residue gas and divide the proceeds of those sales between us and the customer. Some percent of proceeds contracts may also require our customers to pay a monthly reservation fee for processing capacity.
PHMSA: the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration.
Play: a proven geological formation that contains commercial amounts of hydrocarbons.
Produced water: all water removed from a well as a byproduct of the production of hydrocarbons and water removed from a well in connection with operations being conducted on the well, including naturally occurring water in the recovery formation, flow back water recovered during completion and fracturing operations and water entering the recovery formation through water flooding techniques.
Receipt point: the point where a product is received by or into a gathering system, processing facility, or transportation pipeline.
Reservoir: a porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (such as crude oil and/or natural gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.
Residue gas: the natural gas remaining after being processed or treated.
Shale gas: natural gas produced from organic (black) shale formations.
Tailgate: the point at which processed natural gas and NGLs leave a processing facility for transportation to end-user markets.
TBtu: one trillion British Thermal Units.
Tcf: one trillion cubic feet.

Throughput: the volume of products, such as crude oil, natural gas or water, transported or passing through a pipeline, plant, terminal or other facility during a particular period.
Uncommitted shippers (or walk-up shippers): customers that have not signed long-term shipper contracts and have rights under the FERC tariff as to rates and capacity allocation that are different than long-term committed shippers.
Volumetric fee contracts: volumetric fee contracts generally obligate a customer to pay fees based upon the extent to which such customer utilizes our assets for midstream energy services. Unlike firm fee contracts, under volumetric fee contracts our customers are not generally required to pay a charge to reserve an agreed upon amount of capacity and/or deliverability.
Wellhead: the equipment at the surface of a well that is used to control the well's pressure; also, the point at which the hydrocarbons and water exit the ground.
Working gas: the volume of gas in the storage reservoir that is in addition to the cushion or base gas. It may or may not be completely withdrawn during any particular withdrawal season. Conditions permitting, the total working capacity could be used more than once during any season.
Working gas storage capacity: the maximum volume of natural gas that can be cost-effectively injected into a storage facility and extracted during the normal operation of the storage facility. Effective working gas storage capacity excludes base gas and non-cycling working gas.
X/d: the applicable measurement metric per day. For example, MMcf/d means one million cubic feet per day.

PART 1—FINANCIAL INFORMATION
Item 1. Financial Statements
TALLGRASS ENERGY PARTNERS, LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

	June 30, 2016	December 31, 2015
	(in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$1,943	$1,611
Accounts receivable, net	53,033	57,757
Gas imbalances	878	1,227
Inventories	14,754	13,793
Derivative asset at fair value	148	—
Prepayments and other current assets	3,615	2,835
Total Current Assets	74,371	77,223
Property, plant and equipment, net	2,007,067	2,025,018
Goodwill	343,288	343,288
Intangible asset, net	95,038	96,546
Derivative asset at fair value	55,967	—
Unconsolidated investment	444,074	—
Deferred financing costs, net	6,882	5,105
Deferred charges and other assets	13,232	14,894
Total Assets	$3,039,919	$2,562,074
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities:		
Accounts payable (including $10,554 at December 31, 2015 related to variable interest entities)	$17,451	$22,218
Accounts payable to related parties	7,191	7,852
Gas imbalances	1,199	1,605
Derivative liabilities at fair value	351	—
Accrued taxes	15,298	13,844
Accrued liabilities	8,136	10,019
Deferred revenue	42,901	26,511
Other current liabilities	6,687	6,880
Total Current Liabilities	99,214	88,929
Long-term debt	1,278,000	753,000
Other long-term liabilities and deferred credits	6,815	5,143
Total Long-term Liabilities	1,284,815	758,143
Commitments and Contingencies		
Equity:		
Common unitholders (75,669,080 and 60,644,232 units issued and outstanding at June 30, 2016 and December 31, 2015, respectively)	2,242,195	1,618,766
General partner (834,391 units issued and outstanding at June 30, 2016 and December 31, 2015)	(619,837)	(348,841)
Total Partners' Equity	1,622,358	1,269,925
Noncontrolling interests	33,532	445,077
Total Equity	1,655,890	1,715,002

Total Liabilities and Equity	$3,039,919	$2,562,074

The accompanying notes are an integral part of these condensed consolidated financial statements.

TALLGRASS ENERGY PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands, except per unit amounts)			
Revenues:				
Crude oil transportation services	$93,322	$74,022	$187,894	$124,403
Natural gas transportation services	28,682	29,041	57,962	61,189
Sales of natural gas, NGLs, and crude oil	16,830	20,011	30,756	41,880
Processing and other revenues	8,097	9,896	15,724	20,173
Total Revenues	146,931	132,970	292,336	247,645
Operating Costs and Expenses:				
Cost of sales (exclusive of depreciation and amortization shown below)	15,958	17,180	29,526	36,773
Cost of transportation services (exclusive of depreciation and amortization shown below)	14,240	13,492	30,396	24,207
Operations and maintenance	13,864	12,408	26,341	21,983
Depreciation and amortization	21,576	20,355	43,268	40,960
General and administrative	13,909	13,451	26,925	26,140
Taxes, other than income taxes	5,639	(271)	13,145	11,026
Loss on disposal of assets	1,849	—	1,849	4,483
Total Operating Costs and Expenses	87,035	76,615	171,450	165,572
Operating Income	59,896	56,355	120,886	82,073
Other Income (Expense):				
Interest expense, net	(9,233)	(3,893)	(16,732)	(7,333)
Unrealized gain on derivative instrument	18,953	—	10,007	—
Equity in earnings of unconsolidated investment	23,321	—	23,321	—
Other income, net	221	769	787	1,481
Total Other Income (Expense)	33,262	(3,124)	17,383	(5,852)
Net income	93,158	53,231	138,269	76,221
Net (income) loss attributable to noncontrolling interests	(1,110)	(8,332)	(2,151)	997
Net income attributable to partners	$92,048	$44,899	$136,118	$77,218
Allocation of income to the limited partners:				
Net income attributable to partners	$92,048	$44,899	$136,118	$77,218
General partner interest in net income	(25,320)	(11,030)	(45,673)	(18,468)
Common and subordinated unitholders' interest in net income	66,728	33,869	90,445	58,750
Basic net income per common and subordinated unit	$0.93	$0.56	$1.30	$1.04
Diluted net income per common and subordinated unit	$0.92	$0.55	$1.29	$1.02
Basic average number of common and subordinated units outstanding	71,975	60,362	69,471	56,566
Diluted average number of common and subordinated units outstanding	72,925	61,225	70,360	57,404

The accompanying notes are an integral part of these condensed consolidated financial statements.
2

TALLGRASS ENERGY PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	Six Months Ended June 30,	
	2016	2015
	(in thousands)	
Cash Flows from Operating Activities:		
Net income	$138,269	$76,221
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	46,077	42,867
Equity in earnings of unconsolidated investment	(23,321)	—
Distributions from unconsolidated investment	23,321	—
Noncash compensation expense	2,635	3,254
Noncash change in fair value of derivative financial instruments	(9,804)	41
Loss on disposal of assets	1,849	4,483
Changes in components of working capital:		
Accounts receivable and other	6,578	(10,215)
Inventories	(1,683)	(6,068)
Accounts payable and accrued liabilities	(2,303)	2,183
Deferred revenue	16,174	4,198
Other operating, net	(1,246)	(4,746)
Net Cash Provided by Operating Activities	196,546	112,218
Cash Flows from Investing Activities:		
Capital expenditures	(28,491)	(49,544)
Acquisition of unconsolidated affiliate	(436,022)	—
Acquisition of Pony Express membership interest	(49,118)	(700,000)
Distributions from unconsolidated investment in excess of cumulative earnings	6,335	—
Contributions to unconsolidated investment	(14,387)	—
Other investing, net	411	(4,648)
Net Cash Used in Investing Activities	(521,272)	(754,192)
Cash Flows from Financing Activities:		
Distributions to unitholders	(127,924)	(67,080)
Acquisition of Pony Express membership interest	(425,882)	—
Contributions from noncontrolling interests	7,273	16,294
Borrowings under revolving credit facility, net	525,000	147,000
Proceeds from public offering, net of offering costs	261,770	551,673
Proceeds from private placement, net of offering costs	90,009	—
Other financing, net	(5,188)	(5,002)
Net Cash Provided by Financing Activities	325,058	642,885
Net Change in Cash and Cash Equivalents	332	911
Cash and Cash Equivalents, beginning of period	1,611	867
Cash and Cash Equivalents, end of period	$1,943	$1,778
Schedule of Noncash Investing and Financing Activities:		
Property, plant and equipment acquired via the cash management agreement with Tallgrass Development, LP	$—	$103,239
Contributions from noncontrolling interests settled via the cash management agreement with Tallgrass Development, LP	$—	$21,525
	$—	$22,266

Distribution to noncontrolling interests settled via the cash management agreement with Tallgrass Development, LP

The accompanying notes are an integral part of these condensed consolidated financial statements.
3

TALLGRASS ENERGY PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(UNAUDITED)

	Limited Partners Common	Limited Partners Subordinated	General Partner	Total Partners' Equity	Noncontrolling Interests	Total Equity
	(in thousands)					
Balance at January 1, 2016	$1,618,766	$ —	$(348,841)	$1,269,925	$ 445,077	$1,715,002
Net income	90,445	—	45,673	136,118	2,151	138,269
Issuance of units to public, net of offering costs	261,770	—	—	261,770	—	261,770
Issuance of units in a private placement, net of offering costs	90,009	—	—	90,009	—	90,009
Noncash compensation expense	3,820	—	—	3,820	—	3,820
Distributions to unitholders	(91,222)	—	(36,702)	(127,924)	—	(127,924)
Acquisition of additional 31.3% membership interest in Pony Express	268,607	—	(279,967)	(11,360)	(417,679)	(429,039)
Contributions from noncontrolling interest	—	—	—	—	7,273	7,273
Distributions to noncontrolling interest	—	—	—	—	(3,290)	(3,290)
Balance at June 30, 2016	$2,242,195	$ —	$(619,837)	$1,622,358	$ 33,532	$1,655,890

	Limited Partners Common	Limited Partners Subordinated	General Partner	Total Partners' Equity	Noncontrolling Interests	Total Equity
	(in thousands)					
Balance at January 1, 2015	$800,333	$ 274,133	$(35,743)	$1,038,723	$ 756,428	$1,795,151
Net income	53,570	5,180	18,468	77,218	(997)	76,221
Issuance of units to public, net of offering costs	551,673	—	—	551,673	—	551,673
Noncash compensation expense	6,000	—	—	6,000	—	6,000
Distributions to unitholders	(47,247)	(7,857)	(11,976)	(67,080)	—	(67,080)
LTIP units tendered by employees to satisfy tax withholding obligations	(6,562)	—	—	(6,562)	—	(6,562)
Contributions from noncontrolling interest	—	—	—	—	68,651	68,651
Distributions to noncontrolling interest	—	—	—	—	(22,607)	(22,607)
Acquisition of additional 33.3% membership interest in Pony Express	—	—	(324,328)	(324,328)	(375,672)	(700,000)
Acquisition of noncontrolling interests	—	—	—	—	(600)	(600)
Conversion of subordinated units	271,456	(271,456)	—	—	—	—
Balance at June 30, 2015	$1,629,223	$ —	$(353,579)	$1,275,644	$ 425,203	$1,700,847

The accompanying notes are an integral part of these condensed consolidated financial statements.
4

TALLGRASS ENERGY PARTNERS, LP
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1. Description of Business

Tallgrass Energy Partners, LP ("TEP" or the "Partnership") is a publicly traded, growth-oriented limited partnership formed to own, operate, acquire and develop midstream energy assets in North America. "We," "us," "our" and similar terms refer to TEP together with its consolidated subsidiaries. We currently provide crude oil transportation to customers in Wyoming, Colorado, and the surrounding regions through Tallgrass Pony Express Pipeline, LLC ("Pony Express"), which owns a crude oil pipeline commencing in Guernsey, Wyoming and terminating in Cushing, Oklahoma that includes a lateral in Northeast Colorado that commences in Weld County, Colorado, and interconnects with the pipeline just east of Sterling, Colorado (the "Pony Express System"). We provide natural gas transportation and storage services for customers in the Rocky Mountain, Midwest and Appalachian regions of the United States through: (1) our 25% membership interest in Rockies Express Pipeline LLC ("Rockies Express"), a Delaware limited liability company which owns the Rockies Express Pipeline, a FERC-regulated natural gas pipeline system extending from Opal, Wyoming and Meeker, Colorado to Clarington, Ohio, (2) the Tallgrass Interstate Gas Transmission system, a FERC-regulated natural gas transportation and storage system located in Colorado, Kansas, Missouri, Nebraska and Wyoming (the "TIGT System"), and (3) the Trailblazer Pipeline system, a FERC-regulated natural gas pipeline system extending from the Colorado and Wyoming border to Beatrice, Nebraska (the "Trailblazer Pipeline") . We also provide services for customers in Wyoming at the Casper and Douglas natural gas processing facilities and the West Frenchie Draw natural gas treating facility (collectively, the "Midstream Facilities"), and NGL transportation services in Northeast Colorado. We perform water business services in Colorado and Texas through BNN Water Solutions, LLC ("Water Solutions"). Our operations are strategically located in and provide services to certain key United States hydrocarbon basins, including the Denver-Julesburg, Powder River, Wind River, Permian and Hugoton-Anadarko Basins and the Niobrara, Mississippi Lime, Eagle Ford, Bakken, Marcellus and Utica shale formations.

Our reportable business segments are:

- Crude Oil Transportation & Logistics—the ownership and operation of a FERC-regulated crude oil pipeline system;
- Natural Gas Transportation & Logistics—the ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities; and
- Processing & Logistics—the ownership and operation of natural gas processing, treating and fractionation facilities, the provision of water business services primarily to the oil and gas exploration and production industry and the transportation of NGLs.

The table below summarizes our equity ownership as of June 30, 2016:

Unit Holder	Limited Partner Common Units	General Partner Units	Percentage of Outstanding Limited Partner Common Units		Percentage of Outstanding Common and General Partner Units	
Public Unitholders	42,795,600	—	56.56	%	55.94	%
Tallgrass Equity, LLC	20,000,000	—	26.43	%	26.14	%
Tallgrass Development, LP [1]	12,873,480	—	17.01	%	16.83	%
Tallgrass MLP GP, LLC [2]	—	834,391	—	%	1.09	%
Total	75,669,080	834,391	100.00	%	100.00	%

(1) As discussed in Note 7 – Risk Management, 3,563,146 of the common units held by Tallgrass Development, LP ("TD") as of June 30, 2016 were subsequently repurchased and deemed cancelled.

(2) Tallgrass MLP GP, LLC (the "general partner") also holds all of TEP's incentive distribution rights.

5

2. Summary of Significant Accounting Policies

Basis of Presentation

These condensed consolidated financial statements and related notes for the three and six months ended June 30, 2016 and 2015 were prepared in accordance with the accounting principles contained in the Financial Accounting Standards Board's Accounting Standards Codification, the single source of generally accepted accounting principles in the United States of America ("GAAP") for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. The year-end balance sheet data was derived from audited financial statements but does not include all disclosures required by GAAP for annual periods. The condensed consolidated financial statements for the three and six months ended June 30, 2016 and 2015 include all normal, recurring adjustments and disclosures that we believe are necessary for a fair statement of the results for the interim periods. In this report, the Financial Accounting Standards Board is referred to as the FASB and the FASB Accounting Standards Codification is referred to as the Codification or ASC. Certain prior period amounts have been reclassified to conform to the current presentation.

Our financial results for the three and six months ended June 30, 2016 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2016. The accompanying condensed consolidated interim financial statements should be read in conjunction with our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2015 ("2015 Form 10-K") filed with the United States Securities and Exchange Commission (the "SEC") on February 17, 2016.

The condensed consolidated financial statements include the accounts of TEP and its subsidiaries and controlled affiliates. Significant intra-entity items have been eliminated in the presentation. Prior to January 1, 2016, Pony Express participated in a cash management agreement with TD, which currently holds a 2.0% common membership interest in Pony Express, under which cash balances were swept periodically and recorded as loans from Pony Express to TD. Effective January 1, 2016, Pony Express entered into a cash management agreement with TEP.

Net income or loss from consolidated subsidiaries that are not wholly-owned by TEP is attributed to TEP and noncontrolling interests. This is done in accordance with substantive profit sharing arrangements, which generally follow the allocation of cash distributions and may not follow the respective ownership percentages held by TEP. Concurrent with TEP's acquisition of an initial 33.3% membership interest in Pony Express effective September 1, 2014, TEP, TD, and Pony Express entered into the Second Amended and Restated Limited Liability Agreement of Tallgrass Pony Express Pipeline, LLC ("the Second Amended Pony Express LLC Agreement"), which provided TEP a minimum quarterly preference payment of $16.65 million (prorated to approximately $5.4 million for the quarter ended September 30, 2014) through the quarter ended September 30, 2015. Effective March 1, 2015 with TEP's acquisition of an additional 33.3% membership interest in Pony Express, the Second Amended Pony Express LLC Agreement was further amended (as amended, "the Pony Express LLC Agreement") to increase the minimum quarterly preference payment to $36.65 million (prorated to approximately $23.5 million for the quarter ended March 31, 2015) and extend the term of the preference period through the quarter ended December 31, 2015. The Pony Express LLC Agreement provides that the net income or loss of Pony Express be allocated, to the extent possible, consistent with the allocation of Pony Express cash distributions. Under the terms of the Pony Express LLC Agreement, Pony Express distributions and net income for periods beginning after December 31, 2015 are attributed to TEP and its noncontrolling interests in accordance with the respective ownership interests.

A variable interest entity ("VIE") is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has a variable interest that could be significant to the VIE and the power to direct the activities that most significantly impact the entity's economic performance. We have presented separately in our condensed consolidated balance sheets, to the extent material, the liabilities of our consolidated VIEs for which creditors do not have recourse to our general credit. Our consolidated VIEs do not have material assets that can only be used to settle specific obligations of the consolidated VIEs. Pony Express was considered to be a VIE under the applicable authoritative guidance prior to our acquisition of an additional 31.3% membership interest effective January 1, 2016. Effective January 1, 2016, Pony Express is no longer considered to be a VIE. We continue to consolidate our membership interest in Pony Express.

Use of Estimates
Certain amounts included in or affecting these condensed consolidated financial statements and related disclosures must be estimated, requiring management to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time the financial statements are prepared. These estimates and assumptions affect the amounts reported for assets, liabilities, revenues, and expenses during the reporting period, and the disclosure of contingent assets and liabilities at the date of the financial statements. Management evaluates these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods it considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from these estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.
New Accounting Pronouncements
Revenue Recognition
In May 2014, the FASB issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers (Topic 606). ASU 2014-09 provides a comprehensive and converged set of principles-based revenue recognition guidelines which supersede the existing industry and transaction-specific standards. The core principle of the new guidance is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this core principle, entities must apply a five step process to (1) identify the contract with a customer; (2) identify the performance obligations in the contract; (3) determine the transaction price; (4) allocate the transaction price to the performance obligations in the contract; and (5) recognize revenue when (or as) the entity satisfies a performance obligation. ASU 2014-09 also mandates disclosure of sufficient information to enable users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The disclosure requirements include qualitative and quantitative information about contracts with customers, significant judgments and changes in judgments, and assets recognized from the costs to obtain or fulfill a contract.
Throughout the first half of 2016, the FASB has issued a series of subsequent updates to the revenue recognition guidance in Topic 606, including ASU No. 2016-08, Revenue from Contracts with Customers (Topic 606): Principal versus Agent Considerations (Reporting Revenue Gross versus Net), ASU No. 2016-10, Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing, and ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients.
The amendments in ASU 2014-09, ASU 2016-08, ASU 2016-10, and ASU 2016-12 are effective for public entities for annual reporting periods beginning after December 15, 2017, and for interim periods within that reporting period. Early application is permitted for annual reporting periods beginning after December 15, 2016. We are currently evaluating the impact of these updates.
ASU No. 2015-11, "Inventory (Topic 330): Simplifying the Measurement of Inventory"
In July 2015, the FASB issued ASU No. 2015-11, Inventory (Topic 330), Simplifying the Measurement of Inventory. ASU 2015-11 establishes a "lower of cost and net realizable value" model for the measurement of most inventory balances. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation.
The amendments in ASU 2015-11 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2016. Early adoption is permitted. We are currently evaluating the impact of ASU 2015-11.
ASU No. 2016-02, "Leases (Topic 842)"
In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842). ASU 2016-02 provides a comprehensive update to the lease accounting topic in the Codification intended to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The amendments in ASU 2016-02 include a revised definition of a lease as well as certain scope exceptions. The changes primarily impact lessee accounting, while lessor accounting is largely unchanged from previous GAAP.

The amendments in ASU 2016-02 are effective for public entities for annual reporting periods beginning after December 15, 2018, and for interim periods within that reporting period. Early application is permitted. We are currently evaluating the impact of ASU 2016-02.

ASU No. 2016-09, "Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting"

In March 2016, the FASB issued ASU No. 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting. ASU 2016-09 simplifies several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. Among other changes, ASU 2016-09 allows an entity to make an entity-wide accounting policy election to either estimate the number of awards expected to vest (consistent with current GAAP) or account for forfeitures when they occur.

The amendments in ASU 2016-09 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2016. Early adoption is permitted. We are currently evaluating the impact of ASU 2016-09.

ASU No. 2015-16, "Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments"

In September 2015, the FASB issued ASU No. 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments. ASU 2015-16 simplifies the accounting for measurement-period adjustments for provisional amounts recognized in a business combination by eliminating the requirement for an acquirer to retrospectively account for measurement-period adjustments. Under the updated guidance, the acquirer must recognize adjustments in the reporting period in which the adjustment amounts are determined and the effect on earnings as a result of the change to the provisional amounts must be calculated as if the accounting had been completed at the acquisition date.

The amendments in ASU 2015-16 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2015. The adoption of ASU 2015-16 did not have a material impact on our financial position and results of operations.

ASU No. 2015-02, "Consolidation (Topic 810): Amendments to the Consolidation Analysis"

In February 2015, the FASB issued ASU No. 2015-02, Consolidation (Topic 810) - Amendments to the Consolidation Analysis. ASU 2015-02 will change the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. ASU 2015-02 will modify the evaluation of whether limited partnerships and other similar legal entities are considered VIEs or voting interest entities, eliminate the presumption that a general partner should consolidate a limited partnership, and change certain aspects of the consolidation analysis for reporting entities that are involved with VIEs, particularly for those with fee arrangements and related party relationships.

The amendments in ASU 2015-02 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2015. The adoption of ASU 2015-02 did not have a material impact on our financial position and results of operations.

ASU No. 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"

In June 2014, the FASB issued ASU No. 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. ASU 2014-12 provides explicit guidance on accounting for share-based payments requiring a specific performance target to be achieved in order for employees to become eligible to vest in the awards when that performance target may be achieved after the requisite service period for the award. The ASU requires that such performance targets be treated as a performance condition, and should not be reflected in the estimate of the grant-date fair value of the award. Instead, compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved.

ASU 2014-12 is effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. The adoption of ASU 2014-12 did not have a material impact on our financial position and results of operations.

3. Acquisitions

Acquisition of a 25% Membership Interest in Rockies Express Pipeline LLC

On March 29, 2016, TD's indirect wholly owned subsidiary Rockies Express Holdings, LLC ("REX Holdings") signed a purchase agreement (the "REX Purchase Agreement") with a unit of Sempra U.S. Gas and Power ("Sempra") to acquire Sempra's 25% membership interest in Rockies Express for cash consideration of $440 million, subject to adjustment under the REX Purchase Agreement.

On April 28, 2016, we announced that TD offered TEP the right to assume the rights and obligations of REX Holdings under the REX Purchase Agreement. On May 6, 2016, TEP REX Holdings, LLC ("TEP REX"), an indirect wholly-owned subsidiary of TEP, and REX Holdings entered into an Assignment and Assumption Agreement pursuant to which REX Holdings assigned to TEP REX all of its rights under the REX Purchase Agreement and, in exchange, TEP REX assumed all of the rights and obligations of REX Holdings under the REX Purchase Agreement. Subsequently on May 6, 2016, TEP REX closed the purchase of a 25% membership interest in Rockies Express from Sempra pursuant to the REX Purchase Agreement for cash consideration of approximately $436.0 million, after making the adjustments to the purchase price required by the REX Purchase Agreement.

Our investment in Rockies Express is recorded under the equity method of accounting and reported as "Unconsolidated investment" on our condensed consolidated balance sheet. As of May 6, 2016, the difference between the fair value of our investment in Rockies Express of $436.0 million and the book value of the underlying net assets of approximately $840.7 million results in a negative basis difference of approximately $404.7 million. The basis difference has been allocated to property, plant and equipment and long-term debt based on their respective fair values at the date of acquisition. The amount of the basis difference allocated to property, plant and equipment is accreted over 35 years, which equates to the 2.86% composite depreciation rate utilized by Rockies Express to depreciate the underlying property, plant and equipment. The amount allocated to long-term debt is amortized over the remaining life of the various debt facilities. The basis difference at June 30, 2016 was allocated as follows:

	Basis Difference (in thousands)	Amortization Period
Long-term debt	$7,002	2 - 25 years
Property, plant and equipment	(411,730)	35 years
Total basis difference	$(404,728)	

During the period from May 6, 2016 to June 30, 2016, we recognized equity in earnings from Rockies Express of $23.3 million, inclusive of the amortization of the negative basis difference discussed above, and received distributions from and made contributions to Rockies Express of $29.7 million and $14.4 million, respectively.

Summarized financial information for Rockies Express is as follows:

	June 30, 2016 (in thousands)
Current assets	$170,874
Noncurrent assets	$6,038,268
Current liabilities	$185,793
Noncurrent liabilities	$2,636,680
Members' equity	$3,386,669

	Period from May 6, 2016 to June 30, 2016 (in thousands)
Revenue	$ 98,161
Operating income	$ 43,832
Net income to Members	$ 84,741

Acquisition of Additional 31.3% Membership Interest in Pony Express

Effective January 1, 2016, TEP acquired an additional 31.3% membership interest in Pony Express in exchange for cash consideration of $475 million and 6,518,000 TEP common units (valued at approximately $268.6 million based on the December 31, 2015 closing price of our common units) issued to TD, for total consideration of approximately $743.6 million. The transaction increased our aggregate membership interest in Pony Express to 98.0%. As part of the transaction, TD granted us an 18 month call option to repurchase the newly issued 6,518,000 common units at a price of $42.50. On the effective date of the acquisition, the call option was valued at $46.0 million. As discussed in Note 7 – Risk Management, on July 21, 2016, we partially exercised the option and repurchased 3,563,146 of the common units, leaving 2,954,854 remaining common units available for repurchase under the call option.

The acquisition of the additional 31.3% membership interest in Pony Express represents a transaction between entities under common control and an acquisition of noncontrolling interests. As a result, financial information for periods prior to the transaction have not been recast to reflect the additional 31.3% membership interest. The transaction resulted in a deemed distribution to our general partner as discussed further in Note 9 – Partnership Equity and Distributions.

Cash outflows to acquire an additional noncontrolling interest in Pony Express are classified as an investing activity in the accompanying condensed consolidated statements of cash flows to the extent the consideration paid was used to directly fund the construction of the underlying assets by the noncontrolling member. Cash outflows to acquire an additional noncontrolling interest in excess of the cost to construct the underlying assets are classified as financing activities. For the six months ended June 30, 2016, $49.1 million of the $475 million paid to acquire the additional 31.3% membership interest in Pony Express was classified as an investing activity and $425.9 million was classified as a financing activity.

TEP Acquisition of BNN Western, LLC

On December 16, 2015, Whiting Oil and Gas Corporation ("Whiting"), BNN Redtail, LLC ("Redtail"), and BNN Western, LLC ("Western"), a newly formed Delaware limited liability company, entered into a definitive Transfer, Purchase and Sale Agreement, pursuant to which Redtail acquired 100% of the outstanding membership interests of Western from Whiting in exchange for total cash consideration of $75 million. Western's assets consist of a fresh water delivery and storage system and produced water gathering and produced water disposal system, which together comprise 62 miles of pipeline along with associated fresh water ponds and disposal wells. As part of the transaction with Whiting, Whiting also executed a five-year fresh water service contract and a nine-year gathering and disposal contract.

At December 31, 2015, the assets acquired and liabilities assumed in the acquisition were recorded at provisional amounts based on the preliminary purchase price allocation. The $75 million purchase price of the assets was allocated entirely to property, plant and equipment. TEP is in the process of obtaining additional information to identify and measure all assets acquired and liabilities assumed in the acquisition within the measurement period. Such provisional amounts will be adjusted if necessary to reflect any new information about facts and circumstances that existed at the acquisition date that, if known, would have affected the measurement of these amounts.

TEP's unaudited pro forma revenue and net income attributable to partners for the three and six months ended June 30, 2015 is presented below as if the acquisition of Western had been completed on January 1, 2015:

	Three Months Ended June 30, 2015	Six Months Ended June 30, 2015
	(in thousands)	
Revenue	$133,447	$248,594
Net income attributable to partners	$45,065	$77,548

The pro forma financial information is not necessarily indicative of what the actual results of operations or financial position of TEP would have been if the transactions had in fact occurred on the date or for the period indicated, nor do they purport to project the results of operations or financial position of TEP for any future periods or as of any date. The pro forma financial information does not give effect to any cost savings, operating synergies, or revenue enhancements expected to result from the transactions or the costs to achieve these cost savings, operating synergies, and revenue enhancements. The pro forma revenue and net income includes adjustments to give effect to TEP's consolidated interest in the estimated results of operations of Western for the periods presented.

4. Related Party Transactions

We have no employees. TD, through its wholly-owned subsidiary Tallgrass Operations, LLC ("Tallgrass Operations"), provided and charged us for direct and indirect costs of services provided to us or incurred on our behalf including employee labor costs, information technology services, employee health and retirement benefits, and all other expenses necessary or appropriate to the conduct of our business. We recorded these costs on the accrual basis in the period in which TD incurred them. On May 17, 2013, in connection with the closing of TEP's initial public offering, TEP and its general partner entered into an Omnibus Agreement with TD and certain of its affiliates, including Tallgrass Operations (the "TEP Omnibus Agreement"). The TEP Omnibus Agreement provides that, among other things, TEP will reimburse TD and its affiliates for all expenses they incur and payments they make on TEP's behalf, including the costs of employee and director compensation and benefits as well as the cost of the provision of certain centralized corporate functions performed by TD, including legal, accounting, cash management, insurance administration and claims processing, risk management, health, safety and environmental, information technology and human resources in each case to the extent reasonably allocable to TEP.

There was no interest income from TD recognized for the three and six months ended June 30, 2016. During the six months ended June 30, 2015 we recognized interest income from TD of $0.4 million on the receivable balance under the Pony Express cash management agreement in effect through December 31, 2015.

Totals of transactions with affiliated companies are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Cost of transportation services	$7,295	$6,233	$14,551	$10,591
Charges to TEP: (1)				
Property, plant and equipment, net	$622	$1,594	$1,521	$2,901
Operation and maintenance	$6,323	$5,825	$12,461	$11,248
General and administrative	$10,251	$9,315	$19,217	$18,571

(1) Charges to TEP, inclusive of Pony Express, include directly charged wages and salaries, other compensation and benefits, and shared services.

Details of balances with affiliates included in "Accounts receivable, net" and "Accounts payable to related parties" in the condensed consolidated balance sheets are as follows:

	June 30, 2016	December 31, 2015
	(in thousands)	
Receivable from related parties:		
Rockies Express Pipeline LLC	$—	$ 15
Total receivable from related parties	$—	$ 15
Accounts payable to related parties:		
Tallgrass Operations, LLC	$7,040	$ 7,792
Tallgrass Equity, LLC	93	36
Deeprock Development, LLC	—	17
Rockies Express Pipeline LLC	58	7
Total accounts payable to related parties	$7,191	$ 7,852

Balances of gas imbalances with affiliated shippers are as follows:

	June 30, 2016	December 31, 2015
	(in thousands)	
Affiliate gas balance receivables	$23	$ 92
Affiliate gas balance payables	$167	$ 227

5. Inventory

The components of inventory at June 30, 2016 and December 31, 2015 consisted of the following:

	June 30, 2016	December 31, 2015
	(in thousands)	
Crude oil	$5,752	$ 2,661
Materials and supplies	6,429	8,581
Natural gas liquids	351	395
Gas in underground storage	2,222	2,156
Total inventory	$14,754	$ 13,793

6. Property, Plant and Equipment

A summary of net property, plant and equipment by classification is as follows:

	June 30, 2016	December 31, 2015
	(in thousands)	
Crude oil pipelines	$1,180,989	$1,172,684
Natural gas pipelines	552,107	550,710
Processing and treating assets	255,767	254,073
Water business assets	80,736	81,098
General and other	81,876	69,181
Construction work in progress	27,182	30,699
Accumulated depreciation and amortization	(171,590)	(133,427)
Total property, plant and equipment, net	$2,007,067	$2,025,018

7. Risk Management

We occasionally enter into derivative contracts with third parties for the purpose of hedging exposures that accompany our normal business activities. Our normal business activities directly and indirectly expose us to risks associated with changes in the market price of crude oil and natural gas, among other commodities. For example, the risks associated with changes in the market price of crude oil and natural gas include, among others (i) pre-existing or anticipated physical crude oil and natural gas sales, (ii) natural gas purchases and (iii) natural gas system use and storage. We have elected not to apply hedge accounting and changes in the fair value of all derivative contracts are recorded in earnings in the period in which the change occurs.

Fair Value of Derivative Contracts

The following table summarizes the fair values of our derivative contracts included in the condensed consolidated balance sheets:

	Balance Sheet Location	June 30, 2016	December 31, 2015
		(in thousands)	
Crude oil derivative contract [1]	Current assets	$148	$ —
Call option derivative [2]	Noncurrent assets	$55,967	$ —
Natural gas derivative contracts [3]	Current liabilities	$351	$ —

(1) As of June 30, 2016, the fair value of crude oil derivative contracts represents the sale of 85,000 barrels in July 2016. As of December 31, 2015 there were no crude oil derivative contracts outstanding.

(2) As discussed in Note 3 – Acquisitions, in conjunction with our acquisition of an additional 31.3% membership interest in Pony Express effective January 1, 2016, TD granted us an 18 month call option to repurchase the newly issued 6,518,000 common units at a price of $42.50.

(3) As of June 30, 2016, the fair value shown for commodity contracts was comprised of derivative volumes for short natural gas fixed-price swaps totaling 0.8 Bcf. As of December 31, 2015 there were no natural gas derivative contracts outstanding.

12

Effect of Derivative Contracts in the Statements of Income

The following table summarizes the impact of derivative contracts for the three and six months ended June 30, 2016 and 2015:

	Location of gain (loss) recognized in income on derivatives	Amount of gain (loss) recognized in income on derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2016	2015	2016	2015
		(in thousands)			
Derivatives not designated as hedging contracts:					
Call option derivative	Unrealized gain on derivative instrument	$18,953	$—	$10,007	$—
Natural gas derivative contracts	Sales of natural gas, NGLs, and crude oil	$(307)	$(131)	$(351)	$(41)
Crude oil derivative contract	Sales of natural gas, NGLs, and crude oil	$148	$—	$148	$—

Exercise of Call Option

On July 21, 2016, we partially exercised the call option granted by TD in January 2016 as discussed in Note 3 – Acquisitions and repurchased 3,563,146 common units for a cash payment of $151.4 million. These common units were deemed canceled upon repurchase by TEP and as of July 21, 2016 are no longer issued and outstanding. As of July 29, 2016, 2,954,854 common units remained available for repurchase under the call option.

Credit Risk

We have counterparty credit risk as a result of our use of derivative contracts. Counterparties to our crude oil and natural gas derivatives consist of major financial institutions. This concentration of counterparties may impact our overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. The counterparty to our call option derivative is TD. Settlement of the call option derivative, when exercised, requires TEP to make a cash payment to TD in exchange for return of the common units.

Our over-the-counter swaps are entered into with counterparties outside central trading organizations such as futures, options or stock exchanges. These contracts are with financial institutions with investment grade credit ratings. While we enter into derivative transactions principally with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that from time to time losses will result from counterparty credit risk in the future. As of June 30, 2016, the fair value of our natural gas commodity derivative contracts was a liability, resulting in no credit exposure from TEP's counterparties as of that date. The maximum potential exposure to credit losses on our crude oil derivative contract at June 30, 2016 was:

	Asset Position (in thousands)
Gross	$ 148
Netting agreement impact	—
Cash collateral held	—
Net Exposure	$ 148

As of June 30, 2016 and December 31, 2015, we did not have any outstanding letters of credit or cash in margin accounts in support of our hedging of commodity price risks associated with the sale of natural gas nor did we have any margin deposits with counterparties associated with natural gas contract positions.

13

Fair Value

Derivative assets and liabilities are measured and reported at fair value. Derivative contracts can be exchange-traded or over-the-counter ("OTC"). Exchange-traded derivative contracts typically fall within Level 1 of the fair value hierarchy if they are traded in an active market. We value exchange-traded derivative contracts using quoted market prices for identical securities.

OTC derivatives are valued using models utilizing a variety of inputs including contractual terms and commodity and interest rate curves. The selection of a particular model and particular inputs to value an OTC derivative contract depends upon the contractual terms of the instrument as well as the availability of pricing information in the market. We use similar models to value similar instruments. For OTC derivative contracts that trade in liquid markets, such as generic forwards and swaps, model inputs can generally be verified and model selection does not involve significant management judgment. Such contracts are typically classified within Level 2 of the fair value hierarchy.

Certain OTC derivative contracts trade in less liquid markets with limited pricing information; as such, the determination of fair value for these derivative contracts is inherently more difficult. Such contracts are classified within Level 3 of the fair value hierarchy. The valuations of these less liquid OTC derivatives are typically impacted by Level 1 and/or Level 2 inputs that can be observed in the market, as well as unobservable Level 3 inputs. Use of a different valuation model or different valuation input values could produce a significantly different estimate of fair value. However, derivative contracts valued using inputs unobservable in active markets are generally not material to our financial statements. When appropriate, valuations are adjusted for various factors including credit considerations. Such adjustments are generally based on available market evidence. In the absence of such evidence, management's best estimate is used.

The call option granted by TD is valued using a Black-Scholes option pricing model. Key inputs to the valuation model include the term of the option, risk free rate, the exercise price and current market price, expected volatility and expected distribution yield of the underlying units. The call option valuation is classified within Level 2 of the fair value hierarchy as the value is based on significant observable inputs.

The following table summarizes the fair value measurements of our derivative contracts as of June 30, 2016 based on the fair value hierarchy established by the Codification:

	Total	Asset Fair Value Measurements Using		
		Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
	(in thousands)			
As of June 30, 2016				
Call option derivative	$55,967	$ —	$ 55,967	$ —
Crude oil derivative contract	$148	$ —	$ 148	$ —

	Total	Liability Fair Value Measurements Using		
		Quoted prices in active markets for identical assets	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)

		(Level 1)		
	(in thousands)			
As of June 30, 2016				
Natural gas derivative contracts	$351	$ —	$ 351	$ —

8. Long-term Debt

Revolving Credit Facility

Effective January 4, 2016, in connection with the acquisition of an additional 31.3% membership interest in Pony Express, TEP exercised the committed accordion feature to increase the total capacity of the revolving credit facility from $1.1 billion to $1.5 billion. In connection with the acquisition of a 25% membership interest in Rockies Express, TEP amended the revolving credit facility to increase the total capacity to $1.75 billion, which increase became effective May 6, 2016.

The following table sets forth the available borrowing capacity under the revolving credit facility as of June 30, 2016 and December 31, 2015:

	June 30, 2016	December 31, 2015
	(in thousands)	
Total capacity under the revolving credit facility	$1,750,000	$1,100,000
Less: Outstanding borrowings under the revolving credit facility [1]	(1,278,000)	(753,000)
Available capacity under the revolving credit facility	$472,000	$347,000

(1) As of July 29, 2016, our outstanding borrowings under the revolving credit facility were approximately $1.423 billion.

The revolving credit facility contains various covenants and restrictive provisions that, among other things, limit or restrict our ability (as well as the ability of our restricted subsidiaries) to incur or guarantee additional debt, incur certain liens on assets, dispose of assets, make certain distributions (including distributions from available cash, if a default or event of default under the credit agreement then exists or would result from making such a distribution), change the nature of our business, engage in certain mergers or make certain investments and acquisitions, enter into non-arms-length transactions with affiliates and designate certain subsidiaries as "Unrestricted Subsidiaries." In addition, we are required to maintain a consolidated leverage ratio of not more than 4.75 to 1.00 (which will be increased to 5.25 to 1.00 for certain measurement periods following the consummation of certain acquisitions) and a consolidated interest coverage ratio of not less than 2.50 to 1.00. As of June 30, 2016, we are in compliance with the covenants required under the revolving credit facility.

The unused portion of the revolving credit facility is subject to a commitment fee, which ranges from 0.300% to 0.500%, based on our total leverage ratio. As of June 30, 2016, the weighted average interest rate on outstanding borrowings was 2.72%. During the six months ended June 30, 2016, our weighted average effective interest rate, including the interest on outstanding borrowings, commitment fees, and amortization of deferred financing costs, was 2.66%.

Fair Value

The following table sets forth the carrying amount and fair value of our long-term debt, which is not measured at fair value in the condensed consolidated balance sheets as of June 30, 2016 and December 31, 2015, but for which fair value is disclosed:

	Fair Value				
	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total	Carrying Amount
	(in thousands)				
June 30, 2016	$—	$ 1,278,000	$ —	$1,278,000	$1,278,000
December 31, 2015	$—	$ 753,000	$ —	$753,000	$753,000

The long-term debt borrowed under the revolving credit facility is carried at amortized cost. As of June 30, 2016 and December 31, 2015, the fair value approximates the carrying amount for the borrowings under the revolving credit facility using a discounted cash flow analysis. We are not aware of any factors that would significantly affect the estimated fair value subsequent to June 30, 2016.

9. Partnership Equity and Distributions

Equity Distribution Agreements

On October 31, 2014, we entered into an equity distribution agreement pursuant to which we may sell from time to time through a group of managers, as our sales agents, common units representing limited partner interests having an aggregate offering price of up to $200 million. On May 13, 2015 the amount was subsequently amended to $100.2 million in order to account for follow-on equity offerings under our S-3 shelf registration statement. On May 17, 2016, we entered into a new equity distribution agreement allowing for the sale of common units with an aggregate offering price of up to $657.5 million. Sales of common units, if any, will be made by means of ordinary brokers' transactions, to or through a market maker or directly on or through an electronic communication network, a "dark pool" or any similar market venue, or as otherwise agreed by the Partnership and one or more of the managers. We intend to use the net cash proceeds from any sale of the units for general partnership purposes, which may include, among other things, the exercise of the Partnership's right to repurchase all or a portion of the 6,518,000 common units issued by the Partnership to TD in connection with the Partnership's acquisition of an additional 31.3% of Pony Express in January 2016, repayment or refinancing of debt, funding for acquisitions, capital expenditures and additions to working capital.

During the six months ended June 30, 2016, we issued and sold 6,081,138 common units with a weighted average sales price of $43.63 per unit under our equity distribution agreements for net cash proceeds of approximately $261.8 million (net of approximately $3.6 million in commissions and professional service expenses).

Private Placement

On April 28, 2016, we issued an aggregate of 2,416,987 common units for net cash proceeds of $90.0 million in a private placement transaction to certain funds managed by Tortoise Capital Advisors, L.L.C. The units were subsequently registered pursuant to our Form S-3/A (File No. 333-210976) filed with the SEC on May 6, 2016, which became effective May 17, 2016.

Tallgrass Development Purchase Program

On February 17, 2016, TEP and Tallgrass Energy GP, LP ("TEGP") announced that the Board of Directors of Tallgrass Energy Holdings, LLC, the sole member of TEGP's general partner and the general partner of TD, has authorized an equity purchase program under which TD may initially purchase up to an aggregate of $100 million of the outstanding Class A shares of TEGP or the outstanding common units of TEP. TD may purchase Class A shares or Common Units from time to time on the open market or in negotiated purchases. The timing and amounts of any such purchases will be subject to market conditions and other factors, and will be in accordance with applicable securities laws and other legal requirements. The purchase plan does not obligate TD to acquire any specific number of Class A shares or Common Units and may be discontinued at any time. No purchases were made under this program during the six months ended June 30, 2016.

Distributions to Holders of Common Units, General Partner Units and Incentive Distribution Rights

Our partnership agreement requires us to distribute our available cash, as defined in the partnership agreement, to unitholders of record on the applicable record date within 45 days after the end of each quarter. The following table shows the distributions for the periods indicated:

Three Months Ended	Date Paid	Distributions Limited Partner Common Units	General Partner Incentive Distribution Rights	General Partner Units	Total	Distributions per Limited Partner Unit
		(in thousands, except per unit amounts)				
June 30, 2016	August 12, 2016[(1)]	$54,442	$24,262	$ 911	$79,615	$ 0.7550
March 31, 2016	May 13, 2016	48,238	19,816	830	68,884	0.7050
December 31, 2015	February 12, 2016	42,984	15,332	724	59,040	0.6400
September 30, 2015	November 13, 2015	36,347	11,567	660	48,574	0.6000
June 30, 2015	August 14, 2015	35,135	10,418	627	46,180	0.5800
March 31, 2015	May 14, 2015	31,322	6,934	530	38,786	0.5200

(1) The distribution announced on July 6, 2016 for the second quarter of 2016 will be paid on August 12, 2016 to unitholders of record at the close of business on July 29, 2016.

Other Contributions and Distributions

During the six months ended June 30, 2016, TEP was deemed to have made a noncash capital distribution of $280.0 million to the general partner, which represents the excess purchase price over the carrying value of the additional 31.3% membership interest in Pony Express acquired effective January 1, 2016. See Note 3 – Acquisitions for additional information regarding the transaction.

During the six months ended June 30, 2015, TEP was deemed to have made a noncash capital distribution of $324.3 million to the general partner, which represents the excess purchase price over the carrying value of the additional 33.3% membership interest in Pony Express acquired effective March 1, 2015. TEP also recognized contributions from noncontrolling interests of $68.7 million, which consisted primarily of contributions from TD to Pony Express to fund construction of the lateral in Northeast Colorado, and distributions to noncontrolling interests of $22.6 million.

10. Net Income per Limited Partner Unit

The Partnership's net income is allocated to the general partner and the limited partners, including the holders of the subordinated units, in accordance with their respective ownership percentages, after giving effect to incentive distributions paid to the general partner. Basic and diluted net income per limited partner unit is calculated by dividing limited partners' interest in net income, less general partner incentive distributions, by the weighted average number of outstanding limited partner units during the period.

We compute earnings per unit using the two-class method for Master Limited Partnerships as prescribed in the FASB guidance. The two-class method requires that securities that meet the definition of a participating security be considered for inclusion in the computation of basic earnings per unit. Under the two-class method, earnings per unit is calculated as if all of the earnings for the period were distributed under the terms of the partnership agreement, regardless of whether the general partner has discretion over the amount of distributions to be made in any particular period, whether those earnings would actually be distributed during a particular period from an economic or practical perspective, or whether the general partner has other legal or contractual limitations on its ability to pay distributions that would prevent it from distributing all of the earnings for a particular period.

We calculate net income available to limited partners based on the distributions pertaining to the current period's net income. After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner and limited partners in accordance with the contractual terms of the partnership agreement and as further prescribed in the FASB guidance under the two-class method.

The two-class method does not impact our overall net income or other financial results; however, in periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing net income per limited partner unit. This result occurs as a larger portion of our aggregate earnings, as if distributed, is allocated to the incentive distribution rights (which are currently held by our general partner), even though we make distributions on the basis of available cash and not earnings. In periods in which our aggregate net income does not exceed our aggregate distributions for such period, the two-class method does not have any impact on our calculation of earnings per limited partner unit.

Basic earnings per unit is computed by dividing net earnings attributable to unitholders by the weighted average number of units outstanding during each period. Diluted earnings per unit reflects the potential dilution of common equivalent units that could occur if equity participation units are converted into common units.

The following table illustrates the Partnership's calculation of net income per common and subordinated unit for the three and six months ended June 30, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands, except per unit amounts)			
Net income	$93,158	$53,231	$138,269	$76,221
Net (income) loss attributable to noncontrolling interests	(1,110)	(8,332)	(2,151)	997
Net income attributable to partners	92,048	44,899	136,118	77,218
General partner interest in net income	(25,320)	(11,030)	(45,673)	(18,468)
Net income available to common and subordinated unitholders	$66,728	$33,869	$90,445	$58,750
Basic net income per common and subordinated unit	$0.93	$0.56	$1.30	$1.04
Diluted net income per common and subordinated unit	$0.92	$0.55	$1.29	$1.02
Basic average number of common and subordinated units outstanding	71,975	60,362	69,471	56,566
Equity Participation Unit equivalent units	950	863	889	838
Diluted average number of common and subordinated units outstanding	72,925	61,225	70,360	57,404

11. Regulatory Matters

There are currently no proceedings challenging the currently effective rates of Pony Express, Rockies Express or Trailblazer Pipeline Company LLC ("Trailblazer"). On October 30, 2015, Tallgrass Interstate Gas Transmission, LLC ("TIGT") filed a general rate case with the FERC pursuant to Section 4 of the Natural Gas Act ("NGA"), discussed in more detail below. Regulators, as well as shippers, do have rights, under circumstances prescribed by applicable law, to challenge the rates that we charge at our regulated entities. Further, applicable law governing service by Pony Express allows parties having standing to file complaints in regard to existing tariff rates and provisions. If the complaint is not resolved, the FERC may conduct a hearing and order a crude oil pipeline like the Pony Express System to make reparations going back for up to two years prior to the date on which a complaint was filed if a rate is found to be unjust and unreasonable. We can provide no assurance that current rates will remain unchallenged. Any successful challenge could have a material, adverse effect on our future earnings and cash flows.

TIGT

General Rate Case Filing – FERC Docket RP16-137

On October 30, 2015, TIGT filed a general rate case with the FERC pursuant to Section 4 of the NGA. The rate case proposed a general system-wide increase in the maximum tariff rates for all firm and interruptible services offered by TIGT. In addition, TIGT proposed certain changes to the transportation rate design of its system to replace the current rate zone structure with a single "postage stamp" rate. TIGT also proposed new incremental charges, including (i) a charge for deliveries made to points without certain electronic flow measurement equipment, and (ii) a Cost Recovery Mechanism ("CRM") charge to completely or partially reimburse TIGT for certain costs it incurred to maintain system safety, environmental compliance and reliability. TIGT also proposed to replace its fixed fuel and lost and unaccounted for ("FL&U") charge with a FL&U tracker that would compensate TIGT for its actual FL&U expenses and adjust each year to reflect the previous period's under/over collection and the forecasted FL&U expense for the upcoming period. TIGT also proposed to implement a power cost tracker to recover the actual power costs incurred by TIGT to power its compressors. Finally, TIGT proposed certain revisions to its FERC Gas Tariff addressing a number of other rate and non-rate matters. Under the NGA and the FERC's regulations, TIGT's shippers and other interested parties, including the FERC's Trial Staff, have a right to challenge any aspect of TIGT's rate case filing. Accordingly, numerous TIGT customers have protested aspects of TIGT's NGA Section 4 rate filing.

On November 30, 2015, the FERC issued an order accepting and suspending the proposed rates and certain proposed tariff records to be effective upon motion May 1, 2016, subject to refund, certain modifications to TIGT's proposed CRM charge, and the outcome of an evidentiary hearing before a FERC Administrative Law Judge (the "Suspension Order"). In the Suspension Order, the FERC also accepted two tariff records related to force majeure events and reservation charge crediting to be effective December 1, 2015, subject to certain modifications. On December 21, 2015, TIGT made a compliance filing with the FERC to modify TIGT's proposed CRM charge and update the tariff records related to force majeure events and reservation charge crediting as directed by the FERC in the Suspension Order. No comments or protests were filed in response to the compliance filing and FERC accepted the compliance filing on February 1, 2016. On March 22, 2016, a Settlement Judge was appointed in the case to assist the participants in exploring the possibility of settlement. On March 31, 2016, the FERC issued an order denying certain rehearing requests concerning the CRM, granting in part a motion to remove certain pro forma tariff records from the hearing, and also requested comments in order to assess the need for a technical conference. The FERC also retained for resolution through hearing the pro forma tariff records related to TIGT's proposed charge at delivery points lacking electronic flow measurement and removed from hearing the other issues related to the pro forma tariff records. Whether any issues will be resolved through technical conference is pending. The FERC also directed TIGT to provide additional information related to certain pro forma tariff records, which TIGT filed on April 14, 2016. On June 23, 2016, the Commission approved the implementation of TIGT's filed postage stamp rates, subject to refund, effective on May 1, 2016.

TIGT has reached an agreement in principle with customers representing a majority of firm fee revenue on the TIGT System for the year ended December 31, 2015 to settle all rate related issues set for hearing in its existing FERC rate case, including the issues of a cost recovery mechanism and a non-Electronic Flow Measurement charge. On May 5, 2016, the Acting Chief Administrative Law Judge issued an Order suspending the procedural schedule in the case as a result of the agreement in principle. On June 8, 2016, TIGT filed with the Commission its offer of settlement which resolves all issues in the case, with the exception of certain non-rate related tariff issues which remain subject to the Commission's review and approval. On June 9, 2016, the Presiding Administrative Law Judge issued an Order shortening the period for any comments on the settlement, such that comments were due by June 13, 2016. No adverse comments were filed. The offer of settlement was certified to the Commission by the Administrative Law Judge on July 14, 2016. The Judge found that the settlement is uncontested, presents no issues of first impression, has no Commission policy implications, and appears to be just, reasonable, and in the public interest. The settlement is now subject to the final approval of the FERC.

Trailblazer

2016 Annual Fuel Tracker Filing – FERC Docket RP16-814-000

On April 1, 2016, Trailblazer made its annual fuel tracker filing with a proposed effective date of May 1, 2016 in Docket No. RP16-814-000. The FERC accepted this filing on April 18, 2016.

Rockies Express

Annual FERC Fuel Tracking Filings – Docket No. RP16-702

On March 1, 2016, Rockies Express made its annual fuel tracker filing with a proposed effective date of April 1, 2016 in Docket No. RP16-702. The FERC issued an order accepting the filing on March 25, 2016.

Seneca Lateral Facilities Conversion

On March 2, 2015 in Docket No. CP15-102-000, Rockies Express filed with FERC an application for (1) authorization to convert certain existing and operating pipeline and compression facilities located in Noble and Monroe Counties, Ohio (Seneca Lateral Facilities described in Docket Nos. CP13-539-000 and CP14-194-000) from Natural Gas Policy Act of 1978 Section 311 authority to Natural Gas Act Section 7 jurisdiction, and (2) issuance of a certificate of public convenience and necessity authorizing Rockies Express to operate and maintain the Seneca Lateral Facilities. On April 7, 2016, the FERC issued a Certificate to Rockies Express granting its requested authorizations. As directed by the FERC, Rockies Express filed revised rates for Natural Gas Act service on the Seneca Lateral and the pipeline announced that Natural Gas Act service would commence on June 1, 2016.

Rockies Express Zone 3 Capacity Enhancement Project

On March 31, 2015 in Docket No. CP15-137-000, Rockies Express filed with FERC an application for authorization to construct and operate (1) three new mainline compressor stations located in Pickaway and Fayette Counties, Ohio and Decatur County, Indiana; (2) additional compressors at an existing compressor station in Muskingum County, Ohio; and (3) certain ancillary facilities. The proposed facilities will increase the Rockies Express Zone 3 east-to-west mainline capacity by 800,000 Dth/d from receipts at Clarington, Ohio to corresponding deliveries of 520,000 Dth/d and 280,000 Dth/d to Lebanon, Ohio and Moultrie County, Illinois, respectively. Pursuant to the FERC's obligations under the National Environmental Policy Act, FERC staff issued an Environmental Assessment for the project on August 31, 2015. On February 25, 2016, the FERC issued a Certificate of Public Convenience and Necessity authorizing Rockies Express to proceed with the project. On March 14, 2016, Rockies Express commenced construction of the project facilities, which are expected to be placed into service in the fourth quarter of 2016.

12. Legal and Environmental Matters

Legal

In addition to the matters discussed below, we are a defendant in various lawsuits arising from the day-to-day operations of our business. Although no assurance can be given, we believe, based on our experiences to date, that the ultimate resolution of such routine items will not have a material adverse impact on our business, financial position, results of operations or cash flows. We have evaluated claims in accordance with the accounting guidance for contingencies that we deem both probable and reasonably estimable and, accordingly, had no reserve for legal claims as of June 30, 2016 or December 31, 2015.

Rockies Express

Mineral Management Service Lawsuit

On June 30, 2009, Rockies Express filed claims against Mineral Management Service, a former unit of the U.S. Department of Interior (collectively "Interior") for breach of its contractual obligation to sign transportation service agreements and to pay approximately $192 million for pipeline capacity that it had agreed to take on Rockies Express. The Civilian Board of Contract Appeals ("CBCA") conducted a trial and ruled that Interior was liable for breach of contract, but limited the damages Interior was required to pay. On September 13, 2013, the United States Court of Appeals for the Federal Circuit issued a decision affirming that Interior was liable for its breach of contract, but reversing the CBCA's decision to limit damages. The case was remanded to the CBCA for the purpose of calculating damages at a hearing. On May 20, 2016, Rockies Express and Interior agreed to resolve the claims in this matter in exchange for a $65 million cash payment to Rockies Express. Interior paid the amount due Rockies Express on June 23, 2016.

19

Ultra Resources

In early 2016, Ultra Resources, Inc. ("Ultra"), defaulted on its firm transportation service agreement for approximately 0.2 Bcf/d through November 11, 2019. In late March 2016, Rockies Express terminated Ultra's service agreement. On April 14, 2016, Rockies Express filed a lawsuit against Ultra for breach of contract and damages in Harris County, Texas, in which Rockies Express seeks approximately $303 million in damages and other relief. Specifically, Rockies Express has asserted that Ultra owes approximately $303 million for past transportation service charges and for reservation charge fees that Rockies Express would have received over the term of the service agreement had Ultra not defaulted, in addition to other amounts owed under law or equity.

On April 29, 2016, Ultra and certain of its debtor affiliates filed for protection under Chapter 11 of the United States Bankruptcy Code in United States Bankruptcy Court for the Southern District of Texas. On May 10, 2016, Ultra filed a notice of bankruptcy in the Harris County state court proceeding, which asserted that pursuant to section 362(a) of the Bankruptcy Code, the filing of Ultra’s Chapter 11 petition operated as a stay of the Harris County state court proceeding. Accordingly, Rockies Express intends to pursue its approximately $303 million claim in Ultra’s Chapter 11 proceeding.

Michels Corporation

On June 17, 2014, Michels Corporation ("Michels") filed a complaint and request for relief against Rockies Express as a result of work performed by Michels to construct the Seneca Lateral Pipeline in Ohio. Michels seeks unspecified damages from Rockies Express and asserts claims of breach of contract, negligent misrepresentation, unjust enrichment and quantum meruit. Michels has also filed notices of Mechanic's Liens in Monroe and Noble Counties, asserting $24.2 million as the amount due. The case is currently scheduled to go to trial in April 2017. Rockies Express also previously filed Petition for Declaratory Judgment, Injunctive Relief and Damages against Michels in Johnson County, Kansas. That claim was dismissed without prejudice in September 2015. Rockies Express believes Michels' claims are without merit and plans to continue to vigorously contest all of the claims in this matter.

Environmental, Health and Safety

We are subject to a variety of federal, state and local laws that regulate permitted activities relating to air and water quality, waste disposal, and other environmental matters. We believe that compliance with these laws will not have a material adverse impact on our business, cash flows, financial position or results of operations. However, there can be no assurances that future events, such as changes in existing laws, the promulgation of new laws, or the development of new facts or conditions will not cause us to incur significant costs. We had environmental reserves of $4.4 million and $4.8 million at June 30, 2016 and December 31, 2015, respectively.

TMID

Casper Plant, EPA Notice of Violation

In August 2011, the EPA and the Wyoming Department of Environmental Quality ("WDEQ") conducted an inspection of the Leak Detection and Repair ("LDAR") Program at the Casper Gas Plant in Wyoming. In September 2011, Tallgrass Midstream, LLC ("TMID") received a letter from the EPA alleging violations of the Standards of Performance of Equipment Leaks for Onshore Natural Gas Processing Plant requirements under the Clean Air Act. TMID received a letter from the EPA concerning settlement of this matter in April 2013 and received additional settlement communications from the EPA and Department of Justice beginning in July 2014. Settlement negotiations are continuing, including the expected inclusion of TIGT as a party to any possible settlement as a result of TIGT owning a compressor that is located adjacent to the Casper Gas Plant site.

Casper Mystery Bridge Superfund Site

The Casper Gas Plant is part of the Mystery Bridge Road/U.S. Highway 20 Superfund Site also known as Casper Mystery Bridge Superfund Site. Remediation work at the Casper Gas Plant has been completed and we have requested that the portion of the site attributable to us be delisted from the National Priorities List.

Casper Gas Plant

On November 25, 2014, WDEQ issued a Notice of Violation for violations of Part 60 Subpart OOOO related to the Depropanizer project (wv-14388, issued 7/9/13) in Docket No. 5506-14. TMID had discussed the issues in a meeting with WDEQ in Cheyenne on November 17, 2014, and submitted a disclosure on November 20, 2014 detailing the regulatory issues and potential violations. The project triggered a modification of Subpart OOOO for the entire plant.

The project equipment as well as plant equipment subjected to Subpart OOOO was not monitored timely, and initial notification was not made timely. Settlement negotiations with WDEQ are currently ongoing.

Trailblazer

Pipeline Integrity Management Program

In 2014 and 2015, Trailblazer conducted smart tool surveys and preliminary analysis on segments of its natural gas pipeline to evaluate the growth rate of corrosion downstream of compressor stations. Trailblazer currently believes that approximately 25 - 35 miles of pipe will likely need to be repaired or replaced in order for the pipeline to operate at its maximum allowable operating pressure of 1,000 pounds per square inch. Such repair or replacement will likely occur over a period of years, depending upon final assessment of corrosion growth rates and the remediation and repair plan implemented by Trailblazer. Trailblazer is currently operating at less than its current maximum allowable operating pressure, public notice of which was first provided in June 2014. The current pressure reduction is not expected to prevent Trailblazer from fulfilling its firm service obligations at existing subscription levels and to date it has not had a material adverse financial impact on TEP.

During 2015, Trailblazer completed 32 excavation digs at an aggregate cost of approximately $1.3 million based on preliminary analysis of the smart tool surveys performed in 2014. Segments of the Trailblazer Pipeline that require full replacement are currently expected to cost in the range of approximately $2.2 million to $2.7 million per mile. Repair costs on sections of the pipeline that do not require full replacement are expected to be less on a per mile basis. Trailblazer is continuing to develop a remediation and repair plan, which involves, among other things, finalizing cost recovery options, establishing project scope and timing and setting an overall project budget. In 2016, Trailblazer intends to replace approximately 8 miles of pipe, install additional ground beds, and continue remediating areas with external control anomalies at an estimated cost of $21.5 million. Trailblazer is currently exploring all possible cost recovery options. It may not ultimately be able to recover any or all of such out of pocket costs unless and until Trailblazer recovers them through a general rate increase or other FERC-approved recovery mechanism, or through negotiated rate agreements with its customers.

In connection with TEP's acquisition of the Trailblazer Pipeline, TD agreed to contractually indemnify TEP for any out of pocket costs incurred between April 1, 2014 and April 1, 2017 related to repairing or remediating the Trailblazer Pipeline, to the extent that such actions are necessitated by external corrosion caused by the pipeline's disbonded Hi-Melt CTE coating. The contractual indemnity provided to TEP by TD is currently capped at $20 million and is subject to an annual $1.5 million deductible.

13. Reporting Segments

Our operations are located in the United States. We are organized into three reporting segments: (1) Crude Oil Transportation & Logistics, (2) Natural Gas Transportation & Logistics, and (3) Processing & Logistics.

Crude Oil Transportation & Logistics

The Crude Oil Transportation & Logistics segment is engaged in the ownership and operation of the Pony Express System, which is a FERC-regulated crude oil pipeline serving the Bakken Shale and other nearby oil producing basins. The mainline portion of the Pony Express System was placed in service in October 2014. The Pony Express System also includes a lateral pipeline in Northeast Colorado, which interconnects with the Pony Express System just east of Sterling, Colorado and was placed in service in the second quarter of 2015.

Natural Gas Transportation & Logistics

The Natural Gas Transportation & Logistics segment is engaged in the ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities that provide services to on-system customers (such as third-party LDCs), industrial users and other shippers. The Natural Gas Transportation & Logistics segment includes our 25% membership interest in Rockies Express effective May 6, 2016, as discussed in Note 3 – Acquisitions.

Processing & Logistics

The Processing & Logistics segment is engaged in the ownership and operation of natural gas processing, treating and fractionation facilities that produce NGLs and residue gas that is sold in local wholesale markets or delivered into pipelines for transportation to additional end markets, as well as water business services provided primarily to the oil and gas exploration and production industry and the transportation of NGLs.

Corporate and Other

Corporate and Other includes corporate overhead costs that are not directly associated with the operations of our reportable segments, such as interest and fees associated with our revolving credit facility, public company costs, and equity-based compensation expense.

These segments are monitored separately by management for performance and are consistent with internal financial reporting. These segments have been identified based on the differing products and services, regulatory environment and the expertise required for their respective operations.

We consider Adjusted EBITDA our primary segment performance measure as we believe it is the most meaningful measure to assess our financial condition and results of operations as a public entity. We define Adjusted EBITDA, a non-GAAP measure, as net income excluding the impact of interest, income taxes, depreciation and amortization, non-cash income or loss related to derivative instruments, non-cash long-term compensation expense, impairment losses, gains or losses on asset or business disposals or acquisitions, gains or losses on the repurchase, redemption or early retirement of debt, and earnings from unconsolidated investments, but including the impact of distributions from unconsolidated investments.

The following tables set forth our segment information for the periods indicated:

	Three Months Ended June 30, 2016			Three Months Ended June 30, 2015		
Revenue:	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	External Revenue
	(in thousands)					
Crude Oil Transportation & Logistics	$93,470	$—	$93,470	$75,219	$—	$75,219
Natural Gas Transportation & Logistics	30,150	(1,410)	28,740	30,969	(1,344)	29,625
Processing & Logistics	24,721	—	24,721	28,126	—	28,126
Corporate and Other	—	—	—	—	—	—
Total Revenue	$148,341	$(1,410)	$146,931	$134,314	$(1,344)	$132,970

	Six Months Ended June 30, 2016			Six Months Ended June 30, 2015		
Revenue:	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	External Revenue
	(in thousands)					
Crude Oil Transportation & Logistics	$188,042	$—	$188,042	$125,600	$—	$125,600
Natural Gas Transportation & Logistics	61,137	(2,765)	58,372	64,579	(2,690)	61,889
Processing & Logistics	45,922	—	45,922	60,156	—	60,156
Corporate and Other	—	—	—	—	—	—
Total Revenue	$295,101	$(2,765)	$292,336	$250,335	$(2,690)	$247,645

Adjusted EBITDA:	Three Months Ended June 30, 2016 Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA	Three Months Ended June 30, 2015 Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA
	(in thousands)					
Crude Oil Transportation & Logistics	$65,760	$1,346	$67,106	$46,320	$1,344	$47,664
Natural Gas Transportation & Logistics	45,763	(1,410)	44,353	16,591	(1,344)	15,247
Processing & Logistics	3,549	64	3,613	7,077	—	7,077
Corporate and Other	(1,089)	—	(1,089)	(1,036)	—	(1,036)
Reconciliation to Net Income:						
Add:						
Equity in earnings of unconsolidated investment			23,321			—
Less:						
Interest expense, net of noncontrolling interest			(9,233)			(3,893)
Depreciation and amortization expense, net of noncontrolling interest			(21,840)			(18,302)
Distributions from unconsolidated investment			(29,656)			—
Non-cash gain (loss) related to derivative instruments, net of noncontrolling interest			18,791			(131)
Non-cash compensation expense			(1,469)			(1,727)
Non-cash loss from disposal of assets			(1,849)			—
Net income attributable to partners			$92,048			$44,899

23

Adjusted EBITDA:	Six Months Ended June 30, 2016 Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA	Six Months Ended June 30, 2015 Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA
	(in thousands)					
Crude Oil Transportation & Logistics	$130,301	$2,691	$132,992	$71,826	$2,690	$74,516
Natural Gas Transportation & Logistics	62,915	(2,765)	60,150	35,837	(2,690)	33,147
Processing & Logistics	6,900	74	6,974	15,795	—	15,795
Corporate and Other	(2,441)	—	(2,441)	(1,671)	—	(1,671)
Reconciliation to Net Income:						
Add:						
Equity in earnings of unconsolidated investment			23,321			—
Non-cash loss allocated to noncontrolling interest			—			9,377
Less:						
Interest expense, net of noncontrolling interest			(16,732)			(7,333)
Depreciation and amortization expense, net of noncontrolling interest			(43,807)			(38,835)
Distributions from unconsolidated investment			(29,656)			—
Non-cash gain (loss) related to derivative instruments, net of noncontrolling interest			9,801			(41)
Non-cash compensation expense			(2,635)			(3,254)
Non-cash loss from disposal of assets			(1,849)			(4,483)
Net income attributable to partners			$136,118			$77,218

Capital Expenditures:	Six Months Ended June 30, 2016	2015
	(in thousands)	
Crude Oil Transportation & Logistics	$19,160	$32,501
Natural Gas Transportation & Logistics	4,115	7,061
Processing & Logistics	5,216	9,982
Corporate and Other	—	—
Total capital expenditures	$28,491	$49,544

Assets:	June 30, 2016	December 31, 2015
	(in thousands)	
Crude Oil Transportation & Logistics	$1,425,917	$1,439,418
Natural Gas Transportation & Logistics	1,142,222	706,576
Processing & Logistics	408,055	409,795
Corporate and Other	63,725	6,285
Total assets	$3,039,919	$2,562,074

14. Subsequent Events
On July 1, 2016, we acquired the remaining 8% noncontrolling equity interest in Water Solutions and additional interests in certain of Water Solutions' subsidiaries from Regency Investments I, LLC and BSEG Water Group LLC for total cash consideration of $6.0 million, which will be accounted for as an acquisition of noncontrolling interest. Subsequent to the closing of the transaction, our aggregate membership interest in Water Solutions is 100%.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

As used in this Quarterly Report, unless the context otherwise requires, "we," "us," "our," the "Partnership," "TEP" and similar terms refer to Tallgrass Energy Partners, LP, together with its consolidated subsidiaries. The term our "general partner" refers to Tallgrass MLP GP, LLC. References to "TD" refer to Tallgrass Development, LP. The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the condensed consolidated financial statements and related notes thereto included elsewhere in this Quarterly Report. Additionally, the following discussion and analysis should be read in conjunction with our audited financial statements and notes thereto, the related "Management's Discussion and Analysis of Financial Condition and Results of Operations," the discussion of "Risk Factors" and the discussion of TEP's "Business" in our Annual Report on Form 10-K for the year ended December 31, 2015 (our "2015 Form 10-K") filed with the United States Securities and Exchange Commission (the "SEC") on February 17, 2016.

A reference to a "Note" herein refers to the accompanying Notes to Condensed Consolidated Financial Statements contained in Item 1.—Financial Statements. In addition, please read "Cautionary Statement Regarding Forward-Looking Statements" and "Risk Factors" for information regarding certain risks inherent in our business.

Cautionary Statement Regarding Forward-Looking Statements

This Quarterly Report and the documents incorporated by reference herein contain forward-looking statements concerning our operations, economic performance and financial condition. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Words such as "could," "will," "may," "assume," "forecast," "position," "predict," "strategy," "expect," "intend," "plan," "estimate," "anticipate," "believe," "project," "budget," "potential," or "continue," and similar expressions are used to identify forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this Quarterly Report include our expectations of plans, strategies, objectives, growth and anticipated financial and operational performance, including guidance regarding our and TD's infrastructure programs, revenue projections, capital expenditures and tax position. Forward-looking statements can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed. A forward-looking statement may include a statement of the assumptions or bases underlying the forward-looking statement. We believe that we have chosen these assumptions or bases in good faith and that they are reasonable. However, when considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this Quarterly Report. Actual results may vary materially. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- our ability to complete and integrate acquisitions from TD or from third parties, including our acquisition of a 25% membership interest in Rockies Express that was completed in May 2016, our purchase of an additional 31.3% membership interest in Pony Express that was completed in January 2016, and our acquisition of water business assets in Weld County, Colorado that was completed in December 2015;
- large or multiple customer defaults, including defaults resulting from actual or potential insolvencies;
- changes in general economic conditions;
- competitive conditions in our industry;
- actions taken by third-party operators, processors and transporters;
- the demand for our services, including crude oil transportation services, natural gas transportation, storage and processing services and water business services;
- our ability to successfully implement our business plan;
- our ability to complete internal growth projects on time and on budget;
- the price and availability of debt and equity financing;
- the level of production of crude oil, natural gas and other hydrocarbons and the resultant market prices of crude oil, natural gas, NGLs, and other hydrocarbons;
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the availability and price of natural gas and crude oil, and fuels derived from both, to the consumer compared to the price of alternative and competing fuels;

- competition from the same and alternative energy sources;
- energy efficiency and technology trends;

- operating hazards and other risks incidental to transporting crude oil, transporting, storing and processing natural gas, and transporting, gathering and disposing of water produced in connection with hydrocarbon exploration and production activities;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- labor relations;
- changes in tax status;
- the effects of existing and future laws and governmental regulations;
- the effects of future litigation; and
- certain factors discussed elsewhere in this Quarterly Report.

Forward-looking statements speak only as of the date on which they are made. While we may update these statements from time to time, we are not required to do so other than pursuant to the securities laws.

Overview

We are a publicly traded, growth-oriented limited partnership formed in 2013 to own, operate, acquire and develop midstream energy assets in North America. We currently provide crude oil transportation to customers in Wyoming, Colorado, and the surrounding regions through Tallgrass Pony Express Pipeline, LLC ("Pony Express"), which owns a crude oil pipeline commencing in Guernsey, Wyoming and terminating in Cushing, Oklahoma that includes a lateral in Northeast Colorado that commences in Weld County, Colorado, and interconnects with the pipeline just east of Sterling, Colorado (the "Pony Express System"). We provide natural gas transportation and storage services for customers in the Rocky Mountain, Midwest and Appalachian regions of the United States through: (1) our 25% membership interest in Rockies Express Pipeline LLC ("Rockies Express"), a Delaware limited liability company which owns the Rockies Express Pipeline, a FERC-regulated natural gas pipeline system extending from Opal, Wyoming and Meeker, Colorado to Clarington, Ohio, (2) the Tallgrass Interstate Gas Transmission system, a FERC-regulated natural gas transportation and storage system located in Colorado, Kansas, Missouri, Nebraska and Wyoming (the "TIGT System"), and (3) the Trailblazer Pipeline system, a FERC-regulated natural gas pipeline system extending from the Colorado and Wyoming border to Beatrice, Nebraska (the "Trailblazer Pipeline"). We also provide services for customers in Wyoming at the Casper and Douglas natural gas processing facilities and the West Frenchie Draw natural gas treating facility (collectively, the "Midstream Facilities"), and NGL transportation services in Northeast Colorado. We perform water business services in Colorado and Texas through BNN Water Solutions, LLC ("Water Solutions"). Our operations are strategically located in and provide services to certain key United States hydrocarbon basins, including the Denver-Julesburg, Powder River, Wind River, Permian and Hugoton-Anadarko Basins and the Niobrara, Mississippi Lime, Eagle Ford, Bakken, Marcellus and Utica shale formations.

We intend to continue to leverage our relationship with TD and utilize the significant experience of our management team to execute our growth strategy of acquiring midstream assets from TD and third parties, increasing utilization of our existing assets and expanding our systems through construction of additional assets. Our reportable business segments are:

- Crude Oil Transportation & Logistics—the ownership and operation of a FERC-regulated crude oil pipeline system;
- Natural Gas Transportation & Logistics—the ownership and operation of FERC-regulated interstate natural gas pipelines and integrated natural gas storage facilities; and
- Processing & Logistics—the ownership and operation of natural gas processing, treating and fractionation facilities, the provision of water business services primarily to the oil and gas exploration and production industry and the transportation of NGLs.

Recent Developments

Distribution Announced

On July 6, 2016, we announced a cash distribution for the quarter ended June 30, 2016 of $0.755 per common unit. The distribution will be paid on August 12, 2016, to unitholders of record on July 29, 2016.

Exercise of Call Option

On July 21, 2016, we partially exercised the call option granted by TD in January 2016 and repurchased 3,563,146 common units for a cash payment of $151.4 million. These common units were deemed canceled upon repurchase by TEP and as of July 21, 2016 are no longer issued and outstanding. As of July 29, 2016, 2,954,854 common units remained available for repurchase under the call option.

Acquisition of Additional Interest in Water Solutions

On July 1, 2016, we acquired the remaining 8% noncontrolling equity interest in Water Solutions and additional interests in certain of Water Solutions' subsidiaries from Regency Investments I, LLC and BSEG Water Group LLC for total cash consideration of $6.0 million, which will be accounted for as an acquisition of noncontrolling interest. Subsequent to the closing of the transaction, our aggregate membership interest in Water Solutions is 100%.

How We Evaluate Our Operations

We evaluate our results using, among other measures, contract profile and volumes, operating costs and expenses, Adjusted EBITDA and Distributable Cash Flow. Adjusted EBITDA and Distributable Cash Flow are non-GAAP measures and are defined below.

Contract Profile and Volumes

Our results are driven primarily by the volume of crude oil transportation capacity, natural gas transportation and storage capacity, NGL transportation capacity, and water transportation, gathering and disposal capacity under firm fee contracts, as well as the volume of natural gas that we process and the fees assessed for such services.

Operating Costs and Expenses

The primary components of our operating costs and expenses that we evaluate include cost of sales, cost of transportation services, operations and maintenance and general and administrative costs. Our operating expenses are driven primarily by expenses related to the operation, maintenance and growth of our asset base.

Adjusted EBITDA and Distributable Cash Flow

Adjusted EBITDA and Distributable Cash Flow are non-GAAP supplemental financial measures that management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies, may use to assess:

- our operating performance as compared to other publicly traded partnerships in the midstream energy industry, without regard to historical cost basis or, in the case of Adjusted EBITDA, financing methods;
- the ability of our assets to generate sufficient cash flow to make distributions to our unitholders;
- our ability to incur and service debt and fund capital expenditures; and
- the viability of acquisitions and other capital expenditure projects and the returns on investment of various expansion and growth opportunities.

We believe that the presentation of Adjusted EBITDA and Distributable Cash Flow provides useful information to investors in assessing our financial condition and results of operations. Adjusted EBITDA and Distributable Cash Flow should not be considered alternatives to net income, operating income, net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP, nor should Adjusted EBITDA and Distributable Cash Flow be considered alternatives to available cash, operating surplus, distributions of available cash from operating surplus or other definitions in our partnership agreement. Adjusted EBITDA and Distributable Cash Flow have important limitations as analytical tools because they exclude some but not all items that affect net income and net cash provided by operating activities. Additionally, because Adjusted EBITDA and Distributable Cash Flow may be defined differently by other companies in our industry, our definition of Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Non-GAAP Financial Measures

We generally define Adjusted EBITDA as net income excluding the impact of interest, income taxes, depreciation and amortization, non-cash income or loss related to derivative instruments, non-cash long-term compensation expense, impairment losses, gains or losses on asset or business disposals or acquisitions, gains or losses on the repurchase, redemption or early retirement of debt, and earnings from unconsolidated investments, but including the impact of distributions from unconsolidated investments. We also use Distributable Cash Flow, which we generally define as Adjusted EBITDA, plus preferred distributions received from Pony Express in excess of its distributable cash flow attributable to our net interest and adjusted for deficiency payments received from or utilized by Pony Express shippers, less cash interest expense, maintenance capital expenditures, distributions to noncontrolling interests in excess of earnings allocated to noncontrolling interests, and certain cash reserves permitted by our partnership agreement, to analyze our performance. Maintenance capital expenditures are cash expenditures incurred (including expenditures for the construction or development of new capital assets) that we expect to maintain our long-term operating income or operating capacity. These expenditures typically include certain system integrity, compliance and safety improvements. As discussed in Note 2 – Summary of Significant Accounting Policies, prior to December 31, 2015, we received preferred distributions from Pony Express. Effective January 1, 2016 with our acquisition of an additional 31.3% membership interest in Pony Express, distributable cash flow from Pony Express is distributed pro rata based on ownership.

Pony Express collects deficiency payments for barrels committed by the customer to be transported in a month but not physically received for transport or delivered to the customers' agreed upon destination point. These deficiency payments are recorded as a deferred liability until the barrels are physically transported and delivered by TEP.

Earnings at Pony Express prior to December 31, 2015 were allocated between TEP and noncontrolling interests in accordance with a substantive profit sharing arrangement rather than pro rata by ownership. Distributions made by Pony Express to its noncontrolling interests reduce the Distributable Cash Flow available to TEP.

Distributable Cash Flow and Adjusted EBITDA are not presentations made in accordance with GAAP. The following table presents a reconciliation of Adjusted EBITDA to net income and net cash provided by operating activities and a reconciliation of Distributable Cash Flow to net cash provided by operating activities, the most directly comparable GAAP financial measures, for each of the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Reconciliation of Adjusted EBITDA to Net Income				
Net income attributable to partners	$92,048	$44,899	$136,118	$77,218
Add:				
Interest expense, net of noncontrolling interest	9,233	3,893	16,732	7,333
Depreciation and amortization expense, net of noncontrolling interest	21,840	18,302	43,807	38,835
Distributions from unconsolidated investment	29,656	—	29,656	—
Non-cash (gain) loss related to derivative instruments, net of noncontrolling interest	(18,791)	131	(9,801)	41
Non-cash compensation expense	1,469	1,727	2,635	3,254
Non-cash loss from disposal of assets	1,849	—	1,849	4,483
Less:				
Equity in earnings of unconsolidated investment	(23,321)	—	(23,321)	—
Non-cash loss allocated to noncontrolling interest	—	—	—	(9,377)
Adjusted EBITDA	$113,983	$68,952	$197,675	$121,787
Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Cash Provided by Operating Activities				
Net cash provided by operating activities	$107,789	$63,579	$196,546	$112,218
Add:				

Interest expense, net of noncontrolling interest	9,233	3,893	16,732	7,333
Other, including changes in operating working capital	(3,039)	1,480	(15,603)	2,236
Adjusted EBITDA	$113,983	$68,952	$197,675	$121,787
Add:				
Pony Express deficiency payments received, net	8,621	3,416	15,778	3,708
Less:				
Cash interest cost	(8,412)	(3,482)	(15,233)	(6,513)
Maintenance capital expenditures	(2,089)	(3,067)	(4,257)	(4,578)
Distributions to noncontrolling interest in excess of earnings	—	(8,894)	—	(10,997)
Distributable Cash Flow	$112,103	$56,925	$193,963	$103,407

The following table presents a reconciliation of Adjusted EBITDA by segment to segment operating income, the most directly comparable GAAP financial measure, for each of the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Reconciliation of Adjusted EBITDA to Operating Income in the Crude Oil Transportation & Logistics Segment (1)				
Operating income	$53,726	$45,515	$106,392	$59,788
Add:				
Depreciation and amortization expense, net of noncontrolling interest	13,246	9,196	26,164	20,429
Adjusted EBITDA attributable to noncontrolling interests	(1,067)	(8,391)	(2,110)	986
Non-cash gain related to derivative instruments, net of noncontrolling interest	(145)	—	(145)	—
Less:				
Non-cash loss allocated to noncontrolling interest	—	—	—	(9,377)
Segment Adjusted EBITDA	$65,760	$46,320	$130,301	$71,826
Reconciliation of Adjusted EBITDA to Operating Income in the Natural Gas Transportation & Logistics Segment (1)				
Operating income	$10,100	$9,937	$20,764	$22,490
Add:				
Depreciation and amortization expense	5,479	5,754	11,357	11,825
Distributions from unconsolidated investment	29,656	—	29,656	—
Non-cash loss related to derivative instruments	307	131	351	41
Other income, net	221	769	787	1,481
Segment Adjusted EBITDA	$45,763	$16,591	$62,915	$35,837
Reconciliation of Adjusted EBITDA to Operating (Loss) Income in the Processing & Logistics Segment (1)				
Operating (loss) income	$(1,372)	$3,666	$(1,194)	$4,720
Add:				
Depreciation and amortization expense, net of noncontrolling interest	3,115	3,352	6,286	6,581
Non-cash loss from disposal of assets	1,849	—	1,849	4,483
Adjusted EBITDA attributable to noncontrolling interests	(43)	59	(41)	11
Segment Adjusted EBITDA	$3,549	$7,077	$6,900	$15,795
Total Segment Adjusted EBITDA	$115,072	$69,988	$200,116	$123,458
Corporate general and administrative costs	(1,089)	(1,036)	(2,441)	(1,671)
Total Adjusted EBITDA	$113,983	$68,952	$197,675	$121,787

(1) Segment results as presented represent total operating income and Adjusted EBITDA, including intersegment activity, for the Crude Oil Transportation & Logistics, Natural Gas Transportation & Logistics, and Processing & Logistics segments. For reconciliations to the consolidated financial data, see Note 13 – Reporting Segments to the accompanying condensed consolidated financial statements.

29

Results of Operations

The following provides a summary of our consolidated results of operations for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands, except operating data)			
Revenues:				
Crude oil transportation services	$93,322	$74,022	$187,894	$124,403
Natural gas transportation services	28,682	29,041	57,962	61,189
Sales of natural gas, NGLs, and crude oil	16,830	20,011	30,756	41,880
Processing and other revenues	8,097	9,896	15,724	20,173
Total Revenues	146,931	132,970	292,336	247,645
Operating Costs and Expenses:				
Cost of sales (exclusive of depreciation and amortization shown below)	15,958	17,180	29,526	36,773
Cost of transportation services (exclusive of depreciation and amortization shown below)	14,240	13,492	30,396	24,207
Operations and maintenance	13,864	12,408	26,341	21,983
Depreciation and amortization	21,576	20,355	43,268	40,960
General and administrative	13,909	13,451	26,925	26,140
Taxes, other than income taxes	5,639	(271)	13,145	11,026
Loss on disposal of assets	1,849	—	1,849	4,483
Total Operating Costs and Expenses	87,035	76,615	171,450	165,572
Operating Income	59,896	56,355	120,886	82,073
Other Income (Expense):				
Interest expense, net	(9,233)	(3,893)	(16,732)	(7,333)
Unrealized gain on derivative instrument	18,953	—	10,007	—
Equity in earnings of unconsolidated investment	23,321	—	23,321	—
Other income, net	221	769	787	1,481
Total Other Income (Expense)	33,262	(3,124)	17,383	(5,852)
Net income	93,158	53,231	138,269	76,221
Net (income) loss attributable to noncontrolling interests	(1,110)	(8,332)	(2,151)	997
Net income attributable to partners	$92,048	$44,899	$136,118	$77,218
Other Financial Data: (1)				
Adjusted EBITDA	$113,983	$68,952	$197,675	$121,787
Operating Data:				
Crude oil transportation average throughput (Bbls/d) (2)	286,217	237,184	288,746	201,495
Gas transportation average firm contracted volumes (MMcf/d) (3)	1,478	1,520	1,476	1,564
Natural gas processing inlet volumes (MMcf/d)	106	130	102	138

(1) For more information regarding Adjusted EBITDA and a reconciliation of Adjusted EBITDA to its most directly comparable GAAP measure, please see "Non-GAAP Financial Measures" above.

(2) Approximate average daily throughput for the three and six months ended June 30, 2015 is reflective of the volumetric ramp up due to commercial in-service of the Pony Express System beginning in October 2014 and delays in the construction and expansion efforts of third-party pipelines with which Pony Express shares joint tariffs.

(3) Excludes firm contracted volumes of Rockies Express.

Three Months Ended June 30, 2016 Compared to the Three Months Ended June 30, 2015

Revenues. Total revenues were $146.9 million for the three months ended June 30, 2016, compared to $133.0 million for the three months ended June 30, 2015, which represents an increase of $14.0 million, or 10%, in total revenues. The overall increase in revenue was largely driven by increased revenues of $18.3 million in the Crude Oil Transportation & Logistics segment, partially offset by decreased revenues of $3.4 million and $0.8 million in the Processing & Logistics and Natural Gas Transportation & Logistics segments, respectively, as discussed further below.

Operating costs and expenses. Operating costs and expenses were $87.0 million for the three months ended June 30, 2016 compared to $76.6 million for the three months ended June 30, 2015, which represents an increase of $10.4 million, or 14%. The overall increase in operating costs and expenses was primarily driven by increased operating costs and expenses of $10.0 million and $1.6 million in the Crude Oil Transportation & Logistics and Processing & Logistics segments, respectively, partially offset by decreased operating costs and expenses of $1.0 million in the Natural Gas Transportation & Logistics segment, as discussed further below.

Interest expense, net. Interest expense of $9.2 million for the three months ended June 30, 2016 and $3.9 million for the three months ended June 30, 2015 were primarily composed of interest and fees associated with our revolving credit facility. The increase in interest and fees associated with our revolving credit facility is primarily due to increased borrowings to fund a portion of our December 2015 acquisition of BNN Western, LLC ("Western") and our recent acquisitions of an additional 31.3% membership interest in Pony Express effective January 1, 2016 and 25% membership interest in Rockies Express effective May 6, 2016.

Unrealized gain on derivative instrument. Unrealized gain on derivative instrument of $19.0 million represents the change in fair value of the call option received from TD as part of the acquisition of an additional 31.3% membership interest in Pony Express effective January 1, 2016. The call option grants TEP the right to repurchase at a price of $42.50 the 6,518,000 common units issued to TD as a portion of the consideration for the acquisition.

Equity in earnings of unconsolidated investment. Equity in earnings of unconsolidated investment of $23.3 million for the three months ended June 30, 2016 reflects our portion of earnings and the amortization of a negative basis difference of $2.1 million associated with our acquisition of a 25% membership interest in Rockies Express effective May 6, 2016. The equity in earnings for the three months ended June 30, 2016 includes recognition of our portion of the $65 million settlement received by Rockies Express related to the lawsuit between Interior and Rockies Express as discussed in Note 12 – Legal and Environmental Matters.

Other income, net. Other income, net typically includes rental income and income earned from certain customers related to the capital costs we incurred to connect these customers to our system. Other income for the three months ended June 30, 2016 was $0.2 million compared to $0.8 million for the three months ended June 30, 2015.

Net (income) loss attributable to noncontrolling interests. Net income attributable to noncontrolling interests of $1.1 million for the three months ended June 30, 2016 primarily reflects the net income allocated to TD's 2% noncontrolling interest in Pony Express. Net income attributable to noncontrolling interest of $8.3 million for the three months ended June 30, 2015 primarily reflects income allocated to TD's 33.3% noncontrolling interest of Pony Express.

Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015

Revenues. Total revenues were $292.3 million for the six months ended June 30, 2016, compared to $247.6 million for the six months ended June 30, 2015, which represents an increase of $44.7 million, or 18%, in total revenues. The overall increase in revenue was largely driven by increased revenues of $62.4 million in the Crude Oil Transportation & Logistics segment, partially offset by decreased revenues of $14.2 million and $3.4 million in the Processing & Logistics and Natural Gas Transportation & Logistics segments, respectively, as discussed further below.

Operating costs and expenses. Operating costs and expenses were $171.5 million for the six months ended June 30, 2016 compared to $165.6 million for the six months ended June 30, 2015, which represents an increase of $5.9 million, or 4%. The overall increase in operating costs and expenses is primarily driven by increased operating costs and expenses of $15.8 million in the Crude Oil Transportation & Logistics segment, partially offset by decreased operating costs and expenses of $8.3 million and $1.7 million in the Processing & Logistics and Natural Gas Transportation & Logistics segments, respectively, as discussed further below.

Interest expense, net. Interest expense of $16.7 million for the six months ended June 30, 2016 was primarily composed of interest and fees associated with our revolving credit facility. Interest expense of $7.3 million for the six months ended June 30, 2015 was primarily composed of interest and fees associated with our revolving credit facility, partially offset by interest income of $0.4 million on the cash balance swept to TD under the Pony Express cash management agreement. The increase in interest and fees associated with our revolving credit facility is primarily due to increased borrowings to fund a portion of our 2015 acquisitions and our recent acquisitions of an additional 31.3% membership interest in Pony Express effective January 1, 2016 and a 25% membership interest in Rockies Express effective May 6, 2016.

Unrealized gain on derivative instrument. Unrealized gain on derivative instrument of $10.0 million represents the change in fair value of the call option received from TD as part of the acquisition of an additional 31.3% membership interest in Pony Express effective January 1, 2016 as discussed above.

Equity in earnings of unconsolidated investment. Equity in earnings of unconsolidated investment of $23.3 million for the six months ended June 30, 2016 represents earnings associated with our acquisition of a 25% membership interest in Rockies Express as discussed above.

Other income, net. Other income, net typically includes rental income and income earned from certain customers related to the capital costs we incurred to connect these customers to our system. Other income for the six months ended June 30, 2016 was $0.8 million compared to $1.5 million for the six months ended June 30, 2015.

Net (income) loss attributable to noncontrolling interests. Net income attributable to noncontrolling interests of $2.2 million for the six months ended June 30, 2016 primarily reflects the net income allocated to TD's 2% noncontrolling interest in Pony Express. Net loss attributable to noncontrolling interest of $1.0 million for the six months ended June 30, 2015 primarily reflects the net loss allocated to TD's 66.7% noncontrolling interest in Pony Express for the period from January 1, 2015 to February 28, 2015 and TD's 33.3% noncontrolling interest for the period from March 1, 2015 to June 30, 2015.

The following provides a summary of our Crude Oil Transportation & Logistics segment results of operations for the periods indicated:

Segment Financial Data - Crude Oil Transportation & Logistics [1]	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Revenues:				
Crude oil transportation services	$93,322	$74,022	$187,894	$124,403
Sales of natural gas, NGLs, and crude oil	148	1,197	148	1,197
Total revenues	93,470	75,219	188,042	125,600
Operating costs and expenses:				
Cost of sales	—	986	—	986
Cost of transportation services	14,152	11,528	28,647	20,237
Operations and maintenance	3,210	2,015	7,041	3,430
Depreciation and amortization	12,973	11,301	25,612	22,534
General and administrative	5,336	5,155	10,370	10,310
Taxes, other than income taxes	4,073	(1,281)	9,980	8,315
Total operating costs and expenses	39,744	29,704	81,650	65,812
Operating income	$53,726	$45,515	$106,392	$59,788

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 13 – Reporting Segments to the accompanying condensed consolidated financial statements.

Three Months Ended June 30, 2016 Compared to the Three Months Ended June 30, 2015

Revenues. Crude Oil Transportation & Logistics segment revenues were $93.5 million for the three months ended June 30, 2016, compared to $75.2 million for the three months ended June 30, 2015, which represents an increase of $18.3 million, or 24%, in segment revenues primarily due to increased revenues of $13.4 million from a full period of operations on the lateral in Northeast Colorado, which began commercial operations during the second quarter of 2015, and a $2.1 million increase in incremental barrels shipped during the three months ended June 30, 2016.

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation & Logistics segment were $39.7 million for the three months ended June 30, 2016 compared to $29.7 million for the three months ended June 30, 2015, which represents an increase of $10.0 million, or 34%. The overall increase in operating costs and expenses was due to a $5.4 million increase in taxes, other than income taxes, a $2.6 million increase in cost of transportation services, a $1.7 million increase in depreciation and amortization and a $1.2 million increase in operations and maintenance costs, all primarily driven by the costs associated with a full period of operations on the lateral in Northeast Colorado, which began commercial operations during the second quarter of 2015. The increase in taxes, other than income taxes, as a result of the lateral in Northeast Colorado was partially offset by a reduction in property tax estimates during the three months ended June 30, 2016. For the three months ended June 30, 2015, Pony Express recognized a net credit in taxes, other than income taxes, of $1.3 million as a result of revised property tax estimates as a result of successful appeals with state taxing authorities on the assessed value of property.

Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015

Revenues. Crude Oil Transportation & Logistics segment revenues were $188.0 million for the six months ended June 30, 2016, compared to $125.6 million for the six months ended June 30, 2015, which represents an increase of $62.4 million, or 50%, in segment revenues primarily due to increased revenues of $41.1 million from a full period of operations on the lateral in Northeast Colorado, which began commercial operations during the second quarter of 2015, approximately $9.9 million related to the activation of one of our joint tariffs in the second quarter of 2015, and a $9.4 million increase in incremental barrels shipped during the six months ended June 30, 2016.

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation & Logistics segment were $81.7 million for the six months ended June 30, 2016 compared to $65.8 million for the six months ended June 30, 2015, which represents an increase of $15.8 million, or 24%. The overall increase in operating costs and expenses was primarily driven by a $8.4 million increase in cost of transportation services, a $3.6 million increase in operations and maintenance costs, a $3.1 million increase in depreciation and amortization and a $1.7 million increase in taxes, other than income taxes all primarily driven by the costs associated with a full period of operations on the lateral in Northeast Colorado, which began commercial operations during the second quarter of 2015.

The following provides a summary of our Natural Gas Transportation & Logistics segment results of operations for the periods indicated:

Segment Financial Data - Natural Gas Transportation & Logistics [1]	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Revenues:				
Natural gas transportation services	$30,092	$30,385	$60,727	$63,879
Sales of natural gas, NGLs, and crude oil	48	574	396	679
Processing and other revenues	10	10	14	21
Total revenues	30,150	30,969	61,137	64,579
Operating costs and expenses:				
Cost of sales	373	(203)	1,519	(129)
Cost of transportation services	842	2,794	3,297	6,110
Operations and maintenance	7,806	7,359	13,686	13,099
Depreciation and amortization	5,479	5,754	11,357	11,825
General and administrative	4,408	4,424	8,196	8,685
Taxes, other than income taxes	1,142	904	2,318	2,499
Total operating costs and expenses	20,050	21,032	40,373	42,089
Operating income	$10,100	$9,937	$20,764	$22,490

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 13 – Reporting Segments to the accompanying condensed consolidated financial statements.

33

Three Months Ended June 30, 2016 Compared to the Three Months Ended June 30, 2015

Revenues. Natural Gas Transportation & Logistics segment revenues were $30.2 million for the three months ended June 30, 2016, compared to $31.0 million for the three months ended June 30, 2015, which represents a decrease of $0.8 million, or 3%. The decrease in segment revenues was primarily due to a $0.5 million decrease in sales of natural gas, NGLs, and crude oil as a result of lower volumes sold and a 30% decrease in natural gas prices.

Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation & Logistics segment were $20.1 million for the three months ended June 30, 2016 compared to $21.0 million for the three months ended June 30, 2015, which represents a decrease of $1.0 million, or 5%. The overall decrease in operating costs and expenses was primarily driven by a $2.0 million decrease in the cost of transportation services due to lower costs associated with fuel reimbursements as a result of decreased volumes and prices. The decrease was partially offset by a $0.6 million increase in cost of sales and a $0.4 million increase in operations and maintenance due to increased pipeline integrity work at Trailblazer during the three months ended June 30, 2016. Cost of sales during the three months ended June 30, 2015 was negative due to a reduction in our fuel tracker obligations at Trailblazer driven by the FERC approval of our annual fuel tracker filing.

Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015

Revenues. Natural Gas Transportation & Logistics segment revenues were $61.1 million for the six months ended June 30, 2016, compared to $64.6 million for the six months ended June 30, 2015, which represents a decrease of $3.4 million, or 5%, in segment revenues as a result of a $3.2 million decrease in natural gas transportation services primarily driven by decreased prices on fuel reimbursements and warmer weather conditions that created less demand for short-term transportation capacity during the six months ended June 30, 2016 compared to the six months ended June 30, 2015, partially offset by increased tariff rates recognized at TIGT subsequent to the rate case settlement effective May 1, 2016.

Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation & Logistics segment were $40.4 million for the six months ended June 30, 2016, compared to $42.1 million for the six months ended June 30, 2015, which represents a decrease of $1.7 million, or 4%. The overall decrease in operating costs and expenses was primarily driven by a $2.8 million decrease in cost of transportation services due to lower costs associated with fuel reimbursements as a result of decreased prices, a $0.5 million decrease in general and administrative costs due to a reduction in allocated costs to the segment, and a $0.5 million decrease in depreciation and amortization due to lower depreciation rates as of May 1, 2016 as a result of the TIGT System rate case settlement. These decreases were partially offset by a $1.6 million increase in cost of sales due to increased volumes of natural gas sold, partially offset by a 13% decrease in natural gas prices, and a $0.6 million increase in operations and maintenance due to increased pipeline integrity work at Trailblazer during the six months ended June 30, 2016. Cost of sales during the six months ended June 30, 2015 were negative due to a reduction in our fuel tracker obligations at Trailblazer driven by the FERC approval of our annual fuel tracker filing.

The following provides a summary of our Processing & Logistics segment results of operations for the periods indicated:

Segment Financial Data - Processing & Logistics [1]	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)			
Revenues:				
Sales of natural gas, NGLs, and crude oil	$16,634	$18,240	$30,212	$40,004
Processing and other revenues	8,087	9,886	15,710	20,152
Total revenues	24,721	28,126	45,922	60,156
Operating costs and expenses:				
Cost of sales	15,649	16,397	28,081	35,916
Cost of transportation services	592	514	1,143	550
Operations and maintenance	2,848	3,034	5,614	5,454
Depreciation and amortization	3,124	3,300	6,299	6,601
General and administrative	1,607	1,109	3,283	2,220
Taxes, other than income taxes	424	106	847	212
Loss on disposal of assets	1,849	—	1,849	4,483
Total operating costs and expenses	26,093	24,460	47,116	55,436
Operating (loss) income	$(1,372)	$3,666	$(1,194)	$4,720

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 13 – Reporting Segments to the accompanying condensed consolidated financial statements.

Three Months Ended June 30, 2016 Compared to the Three Months Ended June 30, 2015

Revenues. Processing & Logistics segment revenues were $24.7 million for the three months ended June 30, 2016, compared to $28.1 million for the three months ended June 30, 2015, which represents a $3.4 million, or 12%, decrease in segment revenues. The decrease in segment revenues was primarily due to a $1.8 million decrease in processing and other revenues driven by lower processing fees at TMID due to decreased volumes processed, partially offset by increased revenue of $0.4 million primarily attributable to BNN Western, LLC ("Western"), which was acquired on December 16, 2015, and BNN West Texas, LLC ("West Texas"), which commenced operations in March 2016, and a $1.6 million decrease in the sales of natural gas, NGLs, and crude oil driven by lower NGL sales of $1.5 million due to a 20% decrease in NGL prices and lower volumes processed.

Operating costs and expenses. Operating costs and expenses in the Processing & Logistics segment were $26.1 million for the three months ended June 30, 2016 compared to $24.5 million for the three months ended June 30, 2015, which represents an increase of $1.6 million, or 7%. The increase in operating costs and expenses was driven by a $1.8 million loss on Western assets destroyed by fire as a result of a lightning strike during the three months ended June 30, 2016 and a $0.5 million increase in general and administrative costs due to increased costs allocated to Water Solutions as a result of increased operating income related to our acquisitions of Western and West Texas. These increases were partially offset by a $0.7 million decrease primarily in cost of sales due to decreased NGL prices and volumes processed as discussed above.

Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015

Revenues. Processing & Logistics segment revenues were $45.9 million for the six months ended June 30, 2016, compared to $60.2 million for the six months ended June 30, 2015, which represents a $14.2 million, or 24%, decrease in segment revenues. The decrease in segment revenues was primarily due to a $9.8 million decrease in the sales of natural gas, NGLs, and crude oil driven by lower NGL sales of $9.0 million due to a 10% decrease in NGL prices and lower volumes processed and a $4.4 million decrease in processing and other revenues driven by lower processing fees at TMID due to decreased volumes processed, partially offset by a $0.3 million increase in revenue primarily attributable to the recently acquired Western and West Texas assets.

35

Operating costs and expenses. Operating costs and expenses in the Processing & Logistics segment were $47.1 million for the six months ended June 30, 2016 compared to $55.4 million for the six months ended June 30, 2015, which represents a decrease of $8.3 million, or 15%. The decrease in operating costs and expenses was driven by a decrease of $7.8 million in cost of sales, primarily due to decreased NGL prices and volumes processed as discussed above, and a decrease of $2.6 million in loss on disposal of assets as a result of the $1.8 million loss at Western during the six months ended June 30, 2016 as discussed above, compared to a $4.5 million non-cash loss recognized on the sale of compressor assets at TMID in 2015. These decreases were partially offset by a $1.1 million increase in general and administrative costs due to increased costs allocated to Water Solutions as a result of increased operating income related to our acquisitions of Western and West Texas, a $0.6 million increase in taxes, other than income taxes, due to higher property tax estimates for 2016 as a result of the Western acquisition, and a $0.6 million increase in cost of transportation services due to costs associated with Western, which was acquired on December 16, 2015.

Liquidity and Capital Resources Overview

Our primary sources of liquidity for the three months ended June 30, 2016 were borrowings under our revolving credit facility, cash generated from operations, and proceeds from the issuance of common units. We expect our sources of liquidity in the future to include:

- cash generated from our operations;
- borrowing capacity available under our revolving credit facility; and
- future issuances of additional partnership units and/or debt securities.

We believe that cash on hand, cash generated from operations and availability under our revolving credit facility will be adequate to meet our operating needs, our planned short-term maintenance capital and debt service requirements and our planned cash distributions to unitholders. We believe that future internal growth projects or potential acquisitions will be funded primarily through a combination of borrowings under our revolving credit facility and issuances of debt and/or equity securities.

Our total liquidity as of June 30, 2016 and December 31, 2015 was as follows:

	June 30, 2016	December 31, 2015
	(in thousands)	
Cash on hand	$1,943	$1,611
Total capacity under the revolving credit facility	1,750,000	1,100,000
Less: Outstanding borrowings under the revolving credit facility [(1)]	(1,278,000)	(753,000)
Available capacity under the revolving credit facility	472,000	347,000
Total liquidity	$473,943	$348,611

(1) As of July 29, 2016, our outstanding borrowings under the revolving credit facility were approximately $1.423 billion.

Revolving Credit Facility

Effective January 4, 2016, in connection with the acquisition of an additional 31.3% membership interest in Pony Express, TEP exercised the committed accordion feature to increase the total capacity of the revolving credit facility from $1.1 billion to $1.5 billion. In connection with the acquisition of a 25% membership interest in Rockies Express, TEP amended the revolving credit facility to increase the total capacity to $1.75 billion, which increase became effective May 6, 2016.

The revolving credit facility contains various covenants and restrictive provisions that, among other things, limit or restrict our ability (as well as the ability of our restricted subsidiaries) to incur or guarantee additional debt, incur certain liens on assets, dispose of assets, make certain distributions (including distributions from available cash, if a default or event of default under the credit agreement then exists or would result from making such a distribution), change the nature of our business, engage in certain mergers or make certain investments and acquisitions, enter into non-arms-length transactions with affiliates and designate certain subsidiaries as "Unrestricted Subsidiaries." In addition, we are required to maintain a consolidated leverage ratio of not more than 4.75 to 1.00 (which will be increased to 5.25 to 1.00 for certain measurement periods following the consummation of certain acquisitions) and a consolidated interest coverage ratio of not less than 2.50 to 1.00. As of June 30, 2016, we are in compliance with the covenants required under the revolving credit facility.

The unused portion of the revolving credit facility is subject to a commitment fee, which ranges from 0.300% to 0.500%, based on our total leverage ratio. As of June 30, 2016, the weighted average interest rate on outstanding borrowings was 2.72%. During the six months ended June 30, 2016, our weighted average effective interest rate, including the interest on outstanding borrowings, commitment fees, and amortization of deferred financing costs, was 2.66%.

Equity Distribution Agreements

On October 31, 2014, we entered into an equity distribution agreement pursuant to which we may sell from time to time through a group of managers, as our sales agents, common units representing limited partner interests having an aggregate offering price of up to $200 million. On May 13, 2015 the amount was subsequently amended to $100.2 million in order to account for follow-on equity offerings under our S-3 shelf registration statement. On May 17, 2016, we entered into a new equity distribution agreement allowing for the sale of common units with an aggregate offering price of up to $657.5 million. Sales of the common units, if any, will be made by means of ordinary brokers' transactions, to or through a market maker or directly on or through an electronic communication network, a "dark pool" or any similar market venue, or as otherwise agreed by the Partnership and one or more of the managers. We intend to use the net cash proceeds from any sale of the units for general partnership purposes, which may include, among other things, the exercise of the Partnership's right to repurchase all or a portion of the 6,518,000 common units issued by the Partnership to TD in connection with the Partnership's acquisition of an additional 31.3% of Pony Express in January 2016, repayment or refinancing of debt, funding for acquisitions, capital expenditures and additions to working capital.

During the six months ended June 30, 2016, we issued and sold 6,081,138 common units with a weighted average sales price of $43.63 per unit under our equity distribution agreements for net cash proceeds of approximately $261.8 million (net of approximately $3.6 million in commissions and professional service expenses). As of June 30, 2016, approximately $488.1 million in aggregate offering price remained available to be issued and sold under the equity distribution agreements.

Private Placement

On April 28, 2016, we issued an aggregate of 2,416,987 common units for net cash proceeds of $90.0 million in a private placement transaction to certain funds managed by Tortoise Capital Advisors, L.L.C. The units were subsequently registered pursuant to our Form S-3/A (File No. 333-210976) filed with the SEC on May 6, 2016, which became effective May 17, 2016.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. While various other factors may impact our working capital requirements from period to period, our working capital requirements have typically been, and we expect will continue to be, driven by changes in accounts receivable and accounts payable. Factors impacting changes in accounts receivable and accounts payable could include the timing of collections from customers, payments to suppliers, and the level of spending for capital expenditures. Changes in the market prices of energy commodities, primarily NGLs, that we buy and sell in the normal course of business can also impact the timing of changes in accounts receivable and accounts payable.

As of June 30, 2016, we had a working capital deficit of $24.8 million compared to a working capital deficit of $11.7 million at December 31, 2015, which represents a decrease in working capital of $13.1 million. The overall decrease in working capital was primarily attributable to the following:

- an increase in deferred revenue of $16.4 million primarily from deficiency payments collected by Pony Express; and
- a decrease of $4.7 million in accounts receivable primarily due to a decrease in incremental barrels shipped at Pony Express in June 2016 compared to December 2015.

These working capital decreases were partially offset by a decrease of $4.8 million in accounts payable, primarily driven by the timing of project invoices and payment of contractor retainages related to the construction of the Pony Express lateral in Northeast Colorado.

A material adverse change in operations, available financing under our revolving credit facility, or available financing from the equity or debt capital markets could impact our ability to fund our requirements for liquidity and capital resources in the future.

Cash Flows

The following table and discussion presents a summary of our cash flow for the periods indicated:

	Six Months Ended June 30,	
	2016	2015
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$196,546	$112,218
Investing activities	$(521,272)	$(754,192)
Financing activities	$325,058	$642,885

Six Months Ended June 30, 2016 Compared to the Six Months Ended June 30, 2015

Operating Activities. Cash flows provided by operating activities were $196.5 million and $112.2 million for the six months ended June 30, 2016 and 2015, respectively. The increase in net cash flows provided by operating activities of $84.3 million was primarily driven by the increase in operating results as discussed above, distributions received from Rockies Express, and a net increase in cash inflows from changes in working capital, primarily driven by a $16.8 million increase in net cash inflows from accounts receivable due to collection of receivables during the six months ended June 30, 2016 associated primarily with incremental barrels shipped at Pony Express in December 2015, and a $12.0 million increase in deferred revenue associated primarily with deficiency payments received by Pony Express.

Investing Activities. Cash flows used in investing activities were $521.3 million and $754.2 million for the six months ended June 30, 2016 and 2015, respectively. During the six months ended June 30, 2016, net cash used in investing activities were driven by cash outflows of $436.0 million for the acquisition of a 25% membership interest in Rockies Express on May 6, 2016, $49.1 million for a portion of the acquisition of an additional 31.3% membership interest in Pony Express on January 1, 2016, the remainder of which is classified as a financing activity as discussed below, and capital expenditures of $28.5 million, primarily due to post in-service spending on Pony Express System projects. During the six months ended June 30, 2015, net cash used in investing activities were driven by the $700.0 million cash outflow for the acquisition of an additional 33.3% membership interest in Pony Express, which allowed TD to continue funding the pipeline construction at Pony Express, and capital expenditures of $49.5 million, that were primarily due to construction of the Pony Express System, including the lateral in Northeast Colorado.

Financing Activities. Cash flows provided by financing activities were $325.1 million and $642.9 million for the six months ended June 30, 2016 and 2015, respectively. Financing cash inflows for the six months ended June 30, 2016 were primarily driven by:

- net borrowings under the revolving credit facility of $525.0 million;
- the issuance of 6,081,138 common units under the Equity Distribution Agreements for net cash proceeds of $261.8 million;
- the issuance of 2,416,987 common units representing limited partnership interests in a private placement transaction for net cash proceeds of $90.0 million; and
- contributions from noncontrolling interests of $7.3 million, which primarily consisted of contributions from TD to Pony Express.

These financing cash inflows were partially offset by cash outflows of:

- $425.9 million for the portion of the acquisition of an additional 31.3% membership interest in Pony Express which exceeds the cumulative capital spending on the underlying assets acquired; and
- distributions to unitholders of $127.9 million.

Cash flows provided by financing activities for the six months ended June 30, 2015 were primarily driven by:

- net cash proceeds of $551.7 million from the issuance of 11,200,000 common units in a public offering;
- net borrowings under the revolving credit facility of $147.0 million; and
- contributions from noncontrolling interests of $16.3 million, primarily driven by contributions from TD to Pony Express.

These financing cash inflows were partially offset by distributions to unitholders of $67.1 million.

Distributions

We do not have a legal obligation to pay distributions except as provided in our partnership agreement. A distribution of $0.755 per unit, or $79.6 million in the aggregate, for the three months ended June 30, 2016 was announced on July 6, 2016 and will be paid on August 12, 2016 to unitholders of record on July 29, 2016. As of August 3, 2016, we had a total of 72,943,325 common and general partner units outstanding, which equates to an aggregate minimum quarterly distribution of approximately $21.0 million per quarter and approximately $83.9 million per year. We intend to continue to pay quarterly distributions at or above the amount of the minimum quarterly distribution, which is $0.2875 per unit.

Capital Requirements

The midstream energy business can be capital-intensive, requiring significant investment to maintain and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate will continue to consist of, the following:

- maintenance capital expenditures, which are cash expenditures incurred (including expenditures for the construction or development of new capital assets) that we expect to maintain our long-term operating income or operating capacity. These expenditures typically include certain system integrity, compliance and safety improvements; and
- expansion capital expenditures, which are cash expenditures to increase our operating income or operating capacity over the long-term. Expansion capital expenditures include acquisitions or capital improvements (such as additions to or improvements on the capital assets owned, or acquisition or construction of new capital assets).

We expect to incur approximately $49 million for capital expenditures in 2016, of which approximately $37 million is expected for expansion projects and approximately $12 million, net of anticipated reimbursements from affiliates, is expected for maintenance capital expenditures.

The determination of capital expenditures as maintenance or expansion is made at the individual asset level during our budgeting process and as we approve, execute, and monitor our capital spending. The following table summarizes the maintenance and expansion capital expenditures incurred at our consolidated entities:

	Six Months Ended June 30,	
	2016	2015
	(in thousands)	
Maintenance capital expenditures	$4,263	$4,578
Expansion capital expenditures	20,537	117,746
Total capital expenditures incurred	$24,800	$122,324

Capital expenditures incurred represent capital expenditures paid and accrued during the period, inclusive of Pony Express capital expenditures paid by TD on behalf of Pony Express and settled via the cash management agreement during periods prior to December 31, 2015. The decrease in maintenance capital expenditures to $4.3 million for the six months ended June 30, 2016 from $4.6 million for the six months ended June 30, 2015 is primarily driven by decreased maintenance capital expenditures in the Natural Gas Transportation & Logistics segment. Maintenance capital expenditures on our assets occur on a regular schedule, but most major maintenance projects are not required every year so the level of maintenance capital expenditures naturally varies from year to year and from quarter to quarter. The decrease in expansion capital expenditures to $20.5 million for the six months ended June 30, 2016 from $117.7 million for the six months ended June 30, 2015 is primarily driven by spending on the Pony Express System lateral in Northeast Colorado prior to commencement of commercial operations in the second quarter of 2015. Expansion capital expenditures of $20.5 million for the six months ended June 30, 2016 consisted primarily of post in-service spending on Pony Express System projects.

We intend to make cash distributions to our unitholders and our general partner. Due to our cash distribution policy, we expect that we will distribute to our unitholders most of the cash generated by our operations. We expect to fund future capital expenditures with funds generated from our operations, borrowings under our revolving credit facility, the issuance of additional partnership units and/or the issuance of long-term debt. If these sources are not sufficient, we may reduce our discretionary spending.

Contractual Obligations

There have been no material changes in our contractual obligations as reported in our 2015 Form 10-K.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

The critical accounting policies and estimates used in the preparation of our condensed consolidated financial statements are set forth in our 2015 Form 10-K for the year ended December 31, 2015 and have not changed. Our disclosure of critical accounting policies and estimates with respect to goodwill is repeated below for the purpose of providing additional information regarding the impairment testing performed during the first quarter of 2016.

Description	Judgments and Uncertainties	Effect if Actual Results Differ from Assumptions
Impairment of Goodwill		
We evaluate goodwill for impairment annually in the third quarter, and whenever events or changes in circumstances indicate it is more likely than not that the fair value of a reporting unit is less than its carrying amount.	We determine fair value using widely accepted valuation techniques, primarily discounted cash flow and market multiple analyses. These techniques are also used when assigning the purchase price to acquired assets and liabilities. These types of analyses require us to make assumptions and estimates regarding industry and economic factors and the profitability of future business strategies. Our impairment analyses require management to apply judgment in estimating future cash flows as well as asset fair values, including forecasting useful lives of the assets, assessing the probability of different outcomes, including anticipated volumes, contract renewals and changes in our regulated rates, and selecting the discount rate that reflects the risk inherent in future cash flows. It is our policy to conduct impairment testing based on our current business strategy in light of present industry and economic conditions, as well as future expectations.	We primarily use a discounted cash flow analysis, supplemented by a market approach analysis, to perform the assessment. Key assumptions in the analysis include the use of an appropriate discount rate, terminal year multiples, and estimated future cash flows including an estimate of operating and general and administrative costs. In estimating cash flows, we incorporate current market information, as well as historical and other factors, into our forecasted commodity prices. If our assumptions are not appropriate, or future events indicate that our goodwill is impaired, our net income would be impacted by the amount by which the carrying value exceeds the fair value of the reporting unit, to the extent of the balance of goodwill. A prolonged period of lower commodity prices may adversely affect our estimate of future operating results, which could result in future goodwill impairment for reporting units due to the potential impact on our operations and cash flows. We completed our impairment testing of goodwill in the third quarter of 2015 using the methodology described herein, and determined there was no impairment. As a result of a decreased commodity prices in late 2015 and into early 2016, which caused a significant drop in the volumes anticipated from several producers from which TMID receives natural gas for processing, we identified a potential impairment trigger with respect to the $79.2 million of goodwill at the TMID reporting unit, which is a component of our Processing & Logistics segment. We tested TMID's goodwill for impairment as of December 31, 2015 and determined that the fair value of the reporting unit exceeds the carrying value by approximately 21%. As a result, no impairment charge was recorded, however our analysis includes assumptions of a gradual recovery of commodity prices and a corresponding increase in volumes over time. If our outlook for long-term commodity prices is not realized, or our producers further decrease volumes, we could have an impairment in the future. While commodity prices do not have a significant direct exposure to the cash flows projected at TMID, the current commodity price environment has had an indirect impact on TMID’s business as certain producers have significantly reduced their anticipated volumes. Keeping all other assumptions constant, an increase in the discount rate applied of approximately 1.38% or a decrease in overall cash flows by more than 16% would result in a step one failure, however we do not believe that these represent reasonably likely assumptions. If the reporting unit fails step one in the future, we would be required to perform step two of the

goodwill impairment test and up to $79.2 million of goodwill at the TMID reporting unit could be written off in the period that the impairment is triggered.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

As of June 30, 2016 approximately 91% of our reserved processing capacity was subject to firm or volumetric fee contracts, with the majority of fee revenue based on the volumes actually processed. The remaining 9% was subject to commodity sensitive contracts such as percent of proceeds or keep whole processing contracts. The profitability of our commodity sensitive processing contracts that include keep whole or percent of proceeds components is affected by volatility in prevailing NGL and natural gas prices. We do not currently hedge the commodity exposure in our commodity sensitive contracts in our Processing & Logistics segment and we do not expect to in the foreseeable future. Starting in 2014, the prices of crude oil, natural gas, and NGLs were extremely volatile and declined significantly. Downward pressure and volatility on commodity prices continued in 2015 and the first half of 2016 and may continue for the foreseeable future. These declines directly and indirectly resulted in lower realizations and processing volumes on our percent of proceeds and keep whole processing contracts. Our Processing & Logistics segment comprised approximately 3% of our Adjusted EBITDA for both the three and six months ended June 30, 2016.

We have a limited amount of direct commodity price exposure related to crude oil collected as part of our contractual pipeline loss allowance at Pony Express. During the second quarter of 2016, we entered into a derivative contract for the sale of 85,000 barrels of crude oil, which will settle in August 2016. The fair value of these swaps was an asset of approximately $148,000 at June 30, 2016.

Historically, we have also had a limited amount of direct commodity price exposure related to natural gas collected related to electrical compression costs and lost and unaccounted for gas on the TIGT System. We have entered into derivative contracts with third parties for a substantial majority of the gas we expect to collect during the current year for the purpose of hedging our commodity price exposures. As of June 30, 2016, we had natural gas swaps outstanding with a notional volume of approximately 0.8 Bcf short, representing a portion of the natural gas that is expected to be sold by our Natural Gas Transportation & Logistics segment through the first quarter of 2017. The fair value of these swaps was a liability of approximately $351,000 at June 30, 2016.

We measure the risk of price changes in our natural gas swaps utilizing a sensitivity analysis model. The sensitivity analysis measures the potential income or loss (i.e., the change in fair value of the derivative instruments) based upon a hypothetical 10% movement in the underlying quoted market prices. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values. We enter into derivative contracts solely for the purpose of mitigating the risks that accompany certain of our business activities and, therefore, both the sensitivity analysis model and the change in the market value of our outstanding derivative contracts are offset largely by changes in the value of the underlying physical commodity prices. A hypothetical 10% increase in the crude oil price forward curve would result in a decrease of approximately $0.4 million in the net fair value of our crude oil derivative instruments asset for the quarter ended June 30, 2016. A hypothetical 10% increase in the natural gas price forward curve would result in a decrease of approximately $0.2 million in the fair value of our natural gas derivative instruments liability for the quarter ended June 30, 2016 as a result of our hedging program. For the purpose of determining the change in fair value associated with the hypothetical natural gas price increase scenario, we have assumed a parallel shift in the forward curve through the end of 2016.

The Commodity Futures Trading Commission ("CFTC") has promulgated regulations to implement the Dodd-Frank Wall Street Reform and Consumer Protection Act's changes to the Commodity Exchange Act, including the definition of commodity-based swaps subject to those regulations. The CFTC regulations are intended to implement new reporting and record keeping requirements related to those swap transactions and a mandatory clearing and exchange-execution regime for various types, categories or classes of swaps, subject to certain exemptions, including the trade-option and end-user exemptions. Although we anticipate that most, if not all, of our swap transactions should qualify for an exemption to the clearing and exchange-execution requirements, we will still be subject to record keeping and reporting requirements. Other changes to the Commodity Exchange Act made as a result of the Dodd-Frank Wall Street Reform and Consumer Protection Act and the CFTC's implementing regulations could significantly increase the cost of entering into new swaps.

Interest Rate Risk

As described in "Liquidity and Capital Resources Overview" above, TEP currently has a $1.75 billion revolving credit facility with borrowings of approximately $1.3 billion as of June 30, 2016. Borrowings under the revolving credit facility will bear interest, at our option, at either (a) a base rate, which will be a rate equal to the greatest of (i) the prime rate, (ii) the U.S. federal funds rate plus 0.5% and (iii) a one-month reserve adjusted Eurodollar rate plus 1.00% or (b) a reserve adjusted Eurodollar Rate, plus, in each case, an applicable margin. For loans bearing interest based on the base rate, the applicable margin was initially 1.00%, and for loans bearing interest based on the reserve adjusted Eurodollar rate, the applicable margin was initially 2.00%. After June 25, 2014, the applicable margin ranges from 0.75% to 2.75%, based upon our total leverage ratio and whether we have elected the base rate or the reserve adjusted Eurodollar rate. We do not currently hedge the interest rate risk on our borrowings under the revolving credit facility. However, in the future we may consider hedging the interest rate risk or may consider choosing longer Eurodollar borrowing terms in order to fix all or a portion of our borrowings for a period of time. We estimate that a 1% increase in interest rates would decrease the fair value of the debt by $0.3 million based on our debt obligations as of June 30, 2016.

Credit Risk

We are exposed to credit risk. Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We manage our exposure to credit risk associated with customers to whom we extend credit through a credit approval process which includes credit analysis, the establishment of credit limits and ongoing monitoring procedures. We may request letters of credit, cash collateral, prepayments or guarantees as forms of credit support. We have historically experienced only minimal credit losses in connection with our receivables.

A substantial majority of our revenue is produced under long-term firm fee contracts with high-quality customers. The customer base we currently serve under these contracts generally has a strong credit profile, with slightly under 50% of our revenues derived from customers who have an investment grade credit rating or are part of corporate families with investment grade credit ratings as of June 30, 2016. This represents a decrease in the portion of our revenues derived from customers with an investment grade credit rating from 2015, primarily as a result of credit downgrades at several of our customers and throughout the industry due to the current commodity price environment.

We also have indirect credit risk exposure with respect to our investment in Rockies Express. See Item 1A.—Risk Factors for additional information.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rule 13a- 15(e) or Rule 15d- 15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this report, and has concluded that our disclosure controls and procedures are effective to provide reasonable assurance that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the Securities and Exchange Commission's rules and forms including, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosures.

Changes in Internal Control over Financial Reporting

There have been no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the quarter ended June 30, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION
Item 1. Legal Proceedings
See Note 12 – Legal and Environmental Matters to the condensed consolidated financial statements included in Part I—Item 1.—Financial Statements of this Quarterly Report, which is incorporated here by reference.
Item 1A. Risk Factors
Item 1A of our 2015 Form 10-K for the year ended December 31, 2015 and Item 1A of our Form 10-Q for the three months ended March 31, 2016 set forth information relating to important risks and uncertainties that could materially adversely affect our business, financial condition or operating results. Those risk factors continue to be relevant to an understanding of our business, financial condition and operating results for the quarter ended June 30, 2016. Other than as set forth below, there have been no material changes to the risk factors contained in our 2015 Form 10-K for the year ended December 31, 2015 and our Form 10-Q for the three months ended March 31, 2016.
The rates and terms and conditions of our regulated assets are subject to review and possible adjustment by federal and state regulators, which could adversely affect our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.
Our shippers or other interested stakeholders, such as state natural gas utility regulatory agencies, may challenge the rates or the terms and conditions of service applicable to our natural gas or crude oil pipeline tariffs, unless they have entered into agreements not to challenge such tariffs. The FERC has authority to investigate our rates and terms and conditions of service pursuant to NGA Section 5 for natural gas pipelines and the ICA for common carrier oil pipelines. Our crude oil contract shippers have generally agreed not to complain or protest rates unless they are in conflict with their contracts. FERC generally does not regulate crude oil transportation contracts, but contract rates must be filed with FERC and tariff rules and regulations generally apply to contract shippers. Our NGL pipeline is leased to a third party who obtained a temporary waiver for itself from the FERC from the tariff, filing and reporting requirements of the ICA, and during the term of the lease, we operate and maintain the pipeline at the lessee's discretion.
With regard to our natural gas pipelines, Trailblazer initiated a rate proceeding with the FERC pursuant to Section 4 of the NGA on July 1, 2013 to implement a general rate increase to its recourse rates, initiate a rolled-in rate structure for expansion facilities certificated in 2001, and adopt miscellaneous other updates to its General Terms and Conditions in its tariff. On February 24, 2014, Trailblazer submitted to the FERC an uncontested offer of settlement and stipulation to resolve the proceeding by, among other things: (a) setting new maximum recourse rates based upon a “black box” cost of service of approximately $21.1 million; (b) revising the charges and methods for recovery of fuel costs such that the actual volumes of natural gas and costs of electric power incurred to operate Trailblazer’s compressor stations, as well as FL&U gas, are tracked and the charges adjusted in annual periodic rate filings made pursuant to Trailblazer's tariff; (c) providing for revenue sharing of certain interruptible and short-term firm service revenues with eligible maximum recourse rate firm service shippers; (d) establishing a rate moratorium until January 1, 2016; and (e) requiring Trailblazer to file a general rate case with rates to be effective no later than January 1, 2019. The FERC accepted the settlement agreement by letter order on May 29, 2014. Per the terms of the settlement, Trailblazer is required to file a new general rate case with rates to be effective no later than January 1, 2019, and no Settling Party, as defined in the settlement, was permitted to file to change the settlement rates or any other provisions set forth in the settlement prior to January 1, 2016.
On October 30, 2015, TIGT filed a general rate case with the FERC pursuant to Section 4 of the NGA. The rate case proposed a general system-wide increase in the maximum tariff rates for all firm and interruptible services offered by TIGT. In addition, TIGT proposed certain changes to the transportation rate design of its system to replace the current rate zone structure with a single “postage stamp” rate. TIGT also proposed new incremental charges, including (i) a charge for deliveries made to points without certain electronic flow measurement equipment, and (ii) a Cost Recovery Mechanism, or CRM, charge to completely or partially reimburse TIGT for certain costs it incurred to maintain system safety, environmental compliance and reliability. TIGT also proposed to replace its fixed FL&U charge with a FL&U tracker that would compensate TIGT for its actual FL&U expenses and adjust each year to reflect the previous period's under/over collection and the forecasted FL&U expense for the upcoming period. TIGT also proposed to implement a power cost tracker to recover the actual power costs incurred by TIGT to power its compressors. Finally,

TIGT proposed certain revisions to its FERC Gas Tariff addressing a number of other rate and non-rate matters. Under the NGA and the FERC's regulations, TIGT's shippers and other interested parties, including the FERC's Trial Staff, had a right to challenge any aspect of TIGT's rate case filing. Accordingly, numerous TIGT customers protested aspects of TIGT's NGA Section 4 rate filing.

On November 30, 2015, the FERC issued an order accepting and suspending the proposed rates and a majority of the proposed tariff records to be effective upon motion May 1, 2016, subject to refund, certain modifications to TIGT's proposed CRM charge, and the outcome of an evidentiary hearing before a FERC Administrative Law Judge (the “Suspension Order”). In the Suspension Order, the FERC also accepted two tariff records related to force majeure events and reservation charge crediting to be effective December 1, 2015, subject to certain modifications. On December 21, 2015, TIGT made a compliance filing with the FERC to modify TIGT's proposed CRM charge and update the tariff records related to force majeure events and reservation charge crediting as directed by the FERC in the Suspension Order. No comments or protests were filed in response to the compliance filing and FERC accepted the compliance filing on February 1, 2016. On March 22, 2016, a Settlement Judge was appointed in the case to assist the participants with exploring the possibility of settlement. On March 31, 2016, the FERC issued an order denying a request for rehearing with respect to its challenge of TIGT's proposed CRM. The FERC granted in part and denied in part a motion for technical conference, and denied a rehearing request made in the alternative on this issue, and retained for resolution through hearing the pro forma tariff records related to TIGT's proposed charge at delivery points lacking electronic flow measurement and removed from hearing the other issues related to the pro forma tariff records. The FERC also directed TIGT to provide additional information related to certain pro forma tariff records, which TIGT filed on April 14, 2016. One participant filed comments in response to TIGT’s April 14, 2016 filing requesting, inter alia, the FERC to reject certain of TIGT’s proposed pro forma tariff sections, and seeking a technical conference. TIGT filed an answer to such comments, and requested that the FERC deny the request to reject certain proposed pro forma tariff provisions and reject the request for a technical conference. Additional FERC action is pending with respect to the resolution of such pro forma tariff records.

On April 28, 2016, TIGT filed a motion to place the suspended rates and tariff sheets into effect May 1, 2016 and subsequently filed an errata to that motion on May 10, 2016. On June 23, 2016, the FERC issued an order accepting such tariff sheets, effective May 1, 2016, as TIGT requested. TIGT’s proposed rates and tariff sheets (with the exception of the proposed pro forma tariff sections as described above) are now in effect, subject to refund.

On April 27, 2016, TIGT filed a motion to suspend the procedural schedule as the active participants in the proceeding were able to reach a settlement in principal. On May 5, 2016, the Chief Judge granted the motion and suspended the procedural schedule. On June 8, 2016, TIGT filed a Stipulation and Agreement and appendices thereto (the “Settlement”) which, if approved by the FERC, would resolve all matters that could have been raised in TIGT’s Section 4 general rate case filing, as well as any continuing or outstanding issues left unresolved from Docket Nos. RP98-117 and RP11-1494, with the exception of those issues remaining subject to disposition pursuant to the FERC's March 31, 2016 order, as more fully described above and in the Settlement. The Settlement is supported, or not opposed, by customers representing a majority of the contracted responsibility for costs of firm capacity on TIGT for the year ended December 31, 2015 and settles all rate-related issues set for hearing in the case, including the issues of a cost recovery mechanism and a non-Electronic Flow Measurement charge. Both FERC Trial Staff and the LDC Customer Group filed comments in support of the Settlement; no participant filed in opposition to the Settlement. The Settlement remains subject to the approval of the FERC.

On our interstate crude oil pipeline system, the Pony Express System, shippers may generally challenge new or existing rates at any time unless they have contractually agreed not to. As a result of settlement or by order of the FERC following hearing, our rates may be reduced. If a shipper files a lawful complaint, and if the complaint is not resolved with that shipper, to the extent the FERC determines after hearing that we have collected payment on rates that were not previously just and reasonable, we may be required to pay reparations to that shipper for up to two years prior to the date on which a complaint was filed. Regardless of the prospective just and reasonable rate, reparations may not be required below the last rates determined by the FERC to be just and reasonable. In other words, crude oil pipelines are not required to make reparations that refund revenues collected pursuant to rates previously determined to be just and reasonable.

In July 2016, the United States Court of Appeals for the District of Columbia Circuit issued its opinion in United Airlines, Inc., et al. v. FERC, finding that FERC had acted arbitrarily and capriciously when it failed to demonstrate that permitting an interstate petroleum products pipeline organized as a limited partnership to include an income tax allowance in the cost of service underlying its rates in addition to the discounted cash flow return on equity would not result in the pipeline partnership owners double-recovering their income taxes. The court vacated FERC's order and remanded to FERC to consider mechanisms for demonstrating that there is no double recovery as a result of the income tax allowance. There is not likely to be a definitive resolution of these issues for some time, and the ultimate outcome of this proceeding is not certain and could result in changes going forward to the FERC's treatment of income tax allowances in the cost of service or to the discounted cash flow return on equity. Depending upon the resolution of these issues, the cost of service rates of our interstate natural gas pipelines and interstate crude oil pipeline could be affected to the extent we propose new rates or changes to our existing rates or if our rates are subject to complaint or challenge by the FERC.

Successful challenges to rates charged on our natural gas and crude oil pipeline systems, or to the terms and conditions of service on those systems, could have a material adverse effect on our business, results of operations, financial condition and ability to make quarterly cash distributions to our unitholders.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds
None.
Item 3. Defaults Upon Senior Securities
None.
Item 4. Mine Safety Disclosures
Not applicable.
Item 5. Other Information
None.
Item 6. Exhibits

Exhibit No.	Description
10.1	Amendment No. 4 to Credit Agreement, dated as of April 27, 2016, by and among Tallgrass Energy Partners, LP, Barclays Bank PLC, as administrative agent, and a syndicate of lenders named therein (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on April 28, 2016).
10.2*	Membership Interest Purchase Agreement, dated as of March 29, 2016, by and between Sempra REX Holdings, LLC and TEP REX Holdings, LLC (as successor by assignment to Rockies Express Holdings, LLC).
10.3*	Assignment and Assumption Agreement, dated as of May 6, 2016, by and among Rockies Express Holdings, LLC, TEP REX Holdings, LLC and, for the limited purposes set forth therein, Tallgrass Development, LP.
10.4*	Second Amended and Restated Limited Liability Company Agreement of Rockies Express Pipeline LLC, dated effective as of January 1, 2010, among Rockies Express Holdings, LLC (as successor by assignment to Kinder Morgan W2E Pipeline LLC), TEP REX Holdings, LLC (as successor by assignment to Sempra REX Holdings, LLC and P&S Project I, LLC), and P66REX LLC (f/k/a COPREX LLC).
10.5*	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of Rockies Express Pipeline LLC, dated effective as of November 13, 2012, among Kinder Morgan W2E Pipeline LLC, TEP REX Holdings, LLC (as successor by assignment to Sempra REX Holdings, LLC and P&S Project I, LLC), Rockies Express Holdings, LLC and P66REX LLC (f/k/a COPREX LLC).
10.6*	Amendment No. 2 to Second Amended and Restated Limited Liability Company Agreement, dated effective as of May 5, 2016, among Sempra REX Holdings, LLC and P&S Project I, LLC, Rockies Express Holdings, LLC and P66REX LLC.
12.1*	Computation of Ratio of Earnings to Fixed Charges
31.1*	Rule 13a-14(a)/15d-14(a) Certification of David G. Dehaemers, Jr.
31.2*	Rule 13a-14(a)/15d-14(a) Certification of Gary J. Brauchle.
32.1*	Section 1350 Certification of David G. Dehaemers, Jr.
32.2*	Section 1350 Certification of Gary J. Brauchle.

101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

* - filed herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

		Tallgrass Energy Partners, LP (registrant)		
		By:	Tallgrass MLP GP, LLC, its general partner	
Date:	August 3, 2016	By:	/s/ Gary J. Brauchle	
			Name:	Gary J. Brauchle
			Title:	Executive Vice President and Chief Financial Officer

45