Tallgrass Energy Partners, LP
Form 10-Q
August 02, 2017

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, 2017
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, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller reporting company," and "emerging growth 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 ¨
	Emerging growth company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the

Exchange Act. ¨
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 2, 2017, the Registrant had 73,157,633 Common Units and 834,391 General Partner Units outstanding.

TALLGRASS ENERGY PARTNERS, LP
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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 are directly tied 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: an 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: contracts or other arrangements, including tariff provisions, that 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 end users 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.
MDth: one thousand dekatherms.
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.
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: contracts or other arrangements, including tariff provisions, that 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, 2017	December 31, 2016
	(in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$240	$1,873
Accounts receivable, net	58,157	59,536
Gas imbalances	650	1,597
Inventories	11,241	13,093
Derivative assets	220	10,967
Prepayments and other current assets	7,153	7,628
Total Current Assets	77,661	94,694
Property, plant and equipment, net	2,232,754	2,079,232
Goodwill	343,288	343,288
Intangible asset, net	93,258	93,522
Unconsolidated investments	936,939	475,625
Deferred financing costs, net	13,064	4,815
Deferred charges and other assets	11,362	11,037
Total Assets	$3,708,326	$3,102,213
LIABILITIES AND EQUITY		
Current Liabilities:		
Accounts payable	$24,227	$24,122
Accounts payable to related parties	5,895	5,935
Gas imbalances	1,281	1,239
Derivative liabilities	—	556
Accrued taxes	17,246	16,996
Accrued liabilities	18,647	16,702
Deferred revenue	85,566	60,757
Other current liabilities	5,292	6,446
Total Current Liabilities	158,154	132,753
Long-term debt, net	2,087,568	1,407,981
Other long-term liabilities and deferred credits	17,200	7,063
Total Long-term Liabilities	2,104,768	1,415,044
Commitments and Contingencies		
Equity:		
Predecessor Equity	—	82,295
Limited partners (73,028,843 and 72,485,954 common units issued and outstanding at June 30, 2017 and December 31, 2016, respectively)	2,040,537	2,070,495
General partner (834,391 units issued and outstanding at June 30, 2017 and December 31, 2016)	(628,985)	(632,339)
Total Partners' Equity	1,411,552	1,520,451
Noncontrolling interests	33,852	33,965
Total Equity	1,445,404	1,554,416
Total Liabilities and Equity	$3,708,326	$3,102,213

The accompanying notes are an integral part of these condensed consolidated financial statements.
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TALLGRASS ENERGY PARTNERS, LP
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands, except per unit amounts)			
Revenues:				
Crude oil transportation services	$89,855	$93,322	$174,186	$187,894
Natural gas transportation services	29,429	28,682	61,114	57,962
Sales of natural gas, NGLs, and crude oil	22,918	16,830	38,299	30,756
Processing and other revenues	18,661	10,181	31,664	19,571
Total Revenues	160,863	149,015	305,263	296,183
Operating Costs and Expenses:				
Cost of sales (exclusive of depreciation and amortization shown below)	19,386	15,958	31,756	29,526
Cost of transportation services (exclusive of depreciation and amortization shown below)	14,758	11,575	28,261	25,104
Operations and maintenance	15,254	14,270	28,157	27,228
Depreciation and amortization	22,091	21,890	43,494	43,897
General and administrative	14,774	14,322	28,437	27,812
Taxes, other than income taxes	6,912	5,783	15,138	13,433
Contract termination	—	8,061	—	8,061
Loss (gain) on disposal of assets	184	1,849	(1,264)	1,849
Total Operating Costs and Expenses	93,359	93,708	173,979	176,910
Operating Income	67,504	55,307	131,284	119,273
Other Income (Expense):				
Interest expense, net	(19,688)	(9,233)	(34,377)	(16,732)
Unrealized gain on derivative instrument	—	18,953	1,885	10,007
Equity in earnings of unconsolidated investments	42,741	24,022	63,479	24,731
Other income, net	272	221	342	787
Total Other Income (Expense)	23,325	33,963	31,329	18,793
Net income	90,829	89,270	162,613	138,066
Net income attributable to noncontrolling interests	(949)	(1,110)	(1,828)	(2,151)
Net income attributable to partners	$89,880	$88,160	$160,785	$135,915
Allocation of income to the limited partners:				
Net income attributable to partners	$89,880	$88,160	$160,785	$135,915
Predecessor operations interest in net loss	—	3,888	—	203
General partner interest in net income	(37,301)	(25,320)	(67,884)	(45,673)
Net income available to common unitholders	52,579	66,728	92,901	90,445
Basic net income per common unit	$0.72	$0.93	$1.28	$1.30
Diluted net income per common unit	$0.72	$0.92$0.92	$1.27	$1.29
Basic average number of common units outstanding	72,618	71,975	72,581	69,471
Diluted average number of common units outstanding	73,062	72,925	72,972	70,360

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

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

	Six Months Ended June 30,	
	2017	2016
	(in thousands)	
Cash Flows from Operating Activities:		
Net income	$162,613	$138,066
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	47,702	47,106
Equity in earnings of unconsolidated investments	(63,479)	(24,731)
Distributions from unconsolidated investments	63,374	24,636
Changes in components of working capital:		
Accounts receivable and other	2,060	6,356
Accounts payable and accrued liabilities	3,520	6,155
Deferred revenue	24,593	16,174
Other current assets and liabilities	2,241	(1,837)
Other operating, net	(773)	(6,418)
Net Cash Provided by Operating Activities	241,851	205,507
Cash Flows from Investing Activities:		
Acquisition of Rockies Express membership interest	(400,000)	(436,022)
Acquisition of Terminals and NatGas	(140,000)	—
Acquisition of Douglas Gathering System	(128,526)	—
Capital expenditures	(53,995)	(34,860)
Distributions from unconsolidated investments in excess of cumulative earnings	27,308	6,335
Contributions to unconsolidated investments	(17,835)	(14,450)
Acquisition of Pony Express membership interest	—	(49,118)
Other investing, net	(13,986)	411
Net Cash Used in Investing Activities	(727,034)	(527,704)
Cash Flows from Financing Activities:		
Proceeds from issuance of long-term debt	350,000	—
Borrowings under revolving credit facility, net	333,000	525,000
Distributions to unitholders	(179,525)	(127,924)
Proceeds from public offering, net of offering costs	112,762	261,770
Partial exercise of call option	(72,381)	—
Repurchase of common units from TD	(35,335)	—
Acquisition of Pony Express membership interest	—	(425,882)
Proceeds from private placement, net of offering costs	—	90,009
Other financing, net	(24,971)	(444)
Net Cash Provided by Financing Activities	483,550	322,529
Net Change in Cash and Cash Equivalents	(1,633)	332
Cash and Cash Equivalents, beginning of period	1,873	1,611
Cash and Cash Equivalents, end of period	$240	$1,943

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

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

	Predecessor Equity	Limited Partners	General Partner	Total Partners' Equity	Noncontrolling Interests	Total Equity
	(in thousands)					
Balance at January 1, 2017	$82,295	$2,070,495	$(632,339)	$1,520,451	$ 33,965	$1,554,416
Net income	—	92,901	67,884	160,785	1,828	162,613
Issuance of units to public, net of offering costs	—	112,762	—	112,762	—	112,762
Distributions to unitholders	—	(119,279)	(60,246)	(179,525)	—	(179,525)
Noncash compensation expense	—	3,647	—	3,647	—	3,647
LTIP units tendered by employees to satisfy tax withholding obligations	—	(12,273)	—	(12,273)	—	(12,273)
Partial exercise of call option	—	(72,381)	(12,561)	(84,942)	—	(84,942)
Repurchase of common units from TD	—	(35,335)	—	(35,335)	—	(35,335)
Acquisition of Terminals and NatGas	(82,295)	—	(57,705)	(140,000)	—	(140,000)
Acquisition of additional 24.99% membership interest in Rockies Express	—	—	63,681	63,681	—	63,681
Contributions from TD	—	—	2,301	2,301	—	2,301
Contributions from noncontrolling interest	—	—	—	—	867	867
Distributions to noncontrolling interest	—	—	—	—	(2,808)	(2,808)
Balance at June 30, 2017	$—	$2,040,537	$(628,985)	$1,411,552	$ 33,852	$1,445,404

	Predecessor Equity	Limited Partners	General Partner	Total Partners' Equity	Noncontrolling Interests	Total Equity
	(in thousands)					
Balance at January 1, 2016	$71,564	$1,618,766	$(348,841)	$1,341,489	$ 445,077	$1,786,566
Net (loss) income	(203)	90,445	45,673	135,915	2,151	138,066
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
Distributions to unitholders	—	(91,222)	(36,702)	(127,924)	—	(127,924)
Noncash compensation expense	—	3,820	—	3,820	—	3,820
Contributions from noncontrolling interest	—	—	—	—	7,273	7,273
Distributions to noncontrolling interest	—	—	—	—	(3,290)	(3,290)
Acquisition of additional 31.3% membership interest in Pony Express	—	268,607	(279,967)	(11,360)	(417,679)	(429,039)
Distributions to Predecessor Entities, net	(2,530)	—	—	(2,530)	—	(2,530)
Balance at June 30, 2016	$68,831	$2,242,195	$(619,837)	$1,691,189	$ 33,532	$1,724,721

The accompanying notes are an integral part of these condensed consolidated financial statements.
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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. Our operations are 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 and crude oil storage and terminalling facilities;
- 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 gathering, 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.

Crude Oil Transportation & Logistics. 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 FERC-regulated crude oil pipeline commencing in Guernsey, Wyoming and terminating in Cushing, Oklahoma, which includes a lateral in Northeast Colorado commencing in Weld County, Colorado, and interconnecting with the pipeline just east of Sterling, Colorado (the "Pony Express System"). We also provide crude oil storage and terminalling services through our 100% membership interest in Tallgrass Terminals, LLC ("Terminals") acquired effective January 1, 2017, which owns and operates crude oil terminals near Sterling, Colorado (the "Sterling Terminal") and in Weld County, Colorado (the "Buckingham Terminal"). Terminals also owns a 69% membership interest in Deeprock Development, LLC ("Deeprock Development"), which owns a crude oil terminal in Cushing, Oklahoma (the "Cushing Terminal"), inclusive of an additional 49% membership interest in Deeprock Development acquired in July 2017 as discussed in Note 15 – Subsequent Events.

Natural Gas Transportation & Logistics. 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 49.99% membership interest in Rockies Express Pipeline LLC ("Rockies Express"), which owns the Rockies Express Pipeline, a FERC-regulated natural gas pipeline system extending from Opal, Wyoming and Meeker, Colorado to Clarington, Ohio (the "Rockies Express Pipeline"), inclusive of the additional 24.99% membership interest acquired from Tallgrass Development, LP ("TD") effective March 31, 2017 as discussed in Note 3 – Acquisitions, and our 100% membership interest in Tallgrass NatGas Operator, LLC ("NatGas") acquired effective January 1, 2017, which operates the Rockies Express Pipeline, (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").

Processing & Logistics. We provide services for customers in Wyoming through a natural gas gathering system in the Powder River Basin (the "Douglas Gathering System") that was acquired on June 5, 2017, as discussed in Note 3 – Acquisitions, and 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 and Wyoming. We perform water business services, including freshwater transportation and produced water gathering and disposal, in Colorado, Texas, and Wyoming through BNN Water Solutions, LLC ("Water Solutions").

The table below summarizes our equity ownership as of June 30, 2017:

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	47,409,625	—	64.92	%	64.18	%
Tallgrass Equity, LLC	20,000,000	—	27.39	%	27.08	%
Tallgrass Development, LP	5,619,218	—	7.69	%	7.61	%
Tallgrass MLP GP, LLC [(1)]	—	834,391	—	%	1.13	%
Total	73,028,843	834,391	100.00	%	100.00	%

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

The term "Terminals Predecessor" refers to Terminals and the term "NatGas Predecessor" refers to NatGas prior to their acquisition by TEP on January 1, 2017. Terminals Predecessor and NatGas Predecessor are collectively referred to as the Predecessor Entities, as further discussed in Note 2 – Summary of Significant Accounting Policies. Financial results for all prior periods have been recast to reflect the operations of the Predecessor Entities. Predecessor Equity as presented in the condensed consolidated financial statements represents the capital account activity of Terminals Predecessor and NatGas Predecessor prior to January 1, 2017. For additional information regarding these acquisitions, see Note 3 – Acquisitions.

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, 2017 and 2016 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, 2017 and 2016 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, 2017 are not necessarily indicative of the results that may be expected for the full year ending December 31, 2017. 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, 2016 ("2016 Form 10-K") filed with the United States Securities and Exchange Commission (the "SEC") on February 15, 2017.

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. Net income or loss from consolidated subsidiaries that are not wholly-owned by TEP is attributed to TEP and noncontrolling interests in accordance with the respective ownership interests.

As further discussed in Note 3 – Acquisitions, TEP closed the acquisition of Terminals and NatGas effective January 1, 2017. As the acquisitions of Terminals and NatGas are considered transactions between entities under common control, and a change in reporting entity, the financial information presented has been recast to include Terminals and NatGas for all periods presented. Net equity distributions of the Predecessor Entities included in the condensed consolidated financial statements represent transfers of cash as a result of TD's centralized cash management system prior to January 1, 2017 for Terminals and NatGas, under which cash balances were swept daily and recorded as loans from the subsidiaries of TD. These loans were then periodically recorded as equity distributions.

The accompanying condensed consolidated financial statements of TEP include historical cost-basis accounts of the assets and liabilities of the Predecessor Entities for the periods prior to January 1, 2017, the date TEP acquired Terminals and NatGas from TD, and include charges from TD for direct costs and allocations of indirect corporate overhead. Management believes that the allocation methods are reasonable, and that the allocations are representative of costs that would have been incurred on a stand-alone basis. TEP and the Predecessor Entities are all considered "entities under common control" as defined under GAAP and, as such, the transfers between the entities of the assets and liabilities have been recorded by TEP at historical cost.

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.
Accounting Pronouncement Recently Adopted
ASU No. 2017-01, "Business Combinations (Topic 805): Clarifying the Definition of a Business"
In January 2017, the FASB issued Accounting Standards Update ("ASU") No. 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business. ASU 2017-01 clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses by providing a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. This screen reduces the number of transactions that need to be further evaluated. The ASU also narrows the definition of the term "output" so that the term is consistent with how outputs are described under the revenue recognition guidance in Topic 606.
The amendments in ASU 2017-01 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2017. Early adoption is permitted in certain circumstances. We elected to adopt the guidance in ASU 2017-01 effective April 1, 2017, and as a result applied the new guidance to transactions completed during the three months ended June 30, 2017.
ASU No. 2017-04, "Intangibles - Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment"
In January 2017, the FASB issued ASU No. 2017-04, which simplifies the subsequent measurement of goodwill by eliminating "Step 2" from the goodwill impairment test, which involved calculating the implied fair value of goodwill by determining the fair value at the impairment testing date of a reporting unit's assets and liabilities. Instead, under the simplified test approach, an entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit.
The amendments in ASU 2017-04 are effective for public entities for annual periods and interim periods within those annual periods beginning after December 15, 2019. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. We elected to adopt the guidance in ASU 2017-04 effective April 1, 2017, and as a result will apply the new guidance to our annual goodwill impairment tests to be performed as of August 31, 2017.
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 adopted the guidance in ASU 2016-09 effective January 1, 2017 and made a policy election to account for forfeitures when they occur. The adoption of ASU 2016-09 did not have a material impact on our consolidated financial statements.

Accounting Pronouncements Not Yet Adopted

Revenue Recognition

In May 2014, the FASB issued 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 2015 and 2016, the FASB has issued a series of subsequent updates to the revenue recognition guidance in Topic 606, including ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date, 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, ASU No. 2016-12, Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients, and ASU No. 2016-20, Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers.

The amendments in ASU 2014-09, ASU 2016-08, ASU 2016-10, ASU 2016-12, and ASU 2016-20 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 our pending adoption of the revised guidance. The status of our implementation is as follows:

- We have formed an implementation team that meets to discuss implementation challenges, technical interpretations, industry-specific treatment of certain revenue contract types, and project status.
- We are currently reviewing contracts for each revenue stream identified within each of our business segments. Through this process, we are determining and documenting expected changes in revenue recognition upon adoption of the revised guidance.
- We plan to evaluate the potential information technology and internal control changes that will be required for adoption based on the findings from our contract review process.
- We plan to provide internal training and awareness related to the revised guidance to the key stakeholders throughout our organization.

While we have tentatively concluded that the implementation of ASU 2014-09 will not have a material impact on our revenue recognition policies for a substantial number of our contracts, management has identified several areas of potential impact through the contract review process currently underway, including the accounting for non-cash consideration, particularly in our Crude Oil Transportation & Logistics and Processing & Logistics segments, and the timing of revenue recognition with respect to deficiency payments received in our Crude Oil Transportation & Logistics segment. We are currently working with an industry group to develop positions regarding these outstanding items. We are in the process of quantifying the impact of adoption, but we cannot reasonably estimate the full impact of the standard until the industry reaches consensus on these issues. We do anticipate significant changes to our disclosures based on the additional requirements prescribed by the standard. These new disclosures include information regarding the significant judgments used in evaluating when and how revenue is (or will be) recognized and data related to contract assets and liabilities. Additionally, we are currently evaluating our business processes, systems and controls to ensure the accuracy and timeliness of the recognition and disclosure requirements under the new revenue guidance.

We will continue to conduct our contract review process throughout 2017 and, as a result, additional areas of impact may be identified. We expect to adopt the new standard on January 1, 2018 using the modified retrospective approach. This approach allows us to apply the new standard to (i) all new contracts entered into after January 1, 2018 and (ii) all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance as of January 1, 2018 through a cumulative adjustment to equity. Consolidated revenues presented in our comparative financial statements for periods prior to January 1, 2018 would not be revised.

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.

3. Acquisitions

Acquisition of DCP Douglas, LLC

On May 17, 2017, TEP, through its wholly-owned subsidiary Tallgrass Midstream, LLC (“TMID”), entered into a Membership Interest Purchase Agreement with DCP Assets Holding, LP to acquire 100% of the membership interests in DCP Douglas, LLC, which owns the Douglas Gathering System, a natural gas gathering system in the Powder River Basin with approximately 1,500 miles of gathering pipeline connected to TMID's Douglas processing plant, for approximately $128.5 million, subject to working capital adjustments. The acquisition closed on June 5, 2017 and has been accounted for as an asset acquisition, with substantially all of the fair value allocated to the long-lived assets acquired based on their relative fair values.

Acquisition of an Additional 24.99% Membership Interest in Rockies Express

On March 31, 2017, TEP, TD, and Rockies Express Holdings, LLC, entered into a definitive Purchase and Sale Agreement, pursuant to which TEP acquired an additional 24.99% membership interest in Rockies Express from TD in exchange for cash consideration of $400 million. Together with the 25% membership interest in Rockies Express that TEP acquired from a unit of Sempra U.S. Gas and Power on May 6, 2016, this transaction increases TEP’s aggregate membership interest in Rockies Express to 49.99%.

The transfer of the Rockies Express membership interest between TD and the Partnership is considered a transaction between entities under common control, but does not represent a change in reporting entity. Our investment in Rockies Express is recorded under the equity method of accounting and is reported as "Unconsolidated investments" on our condensed consolidated balance sheets. As a result of the common control nature of the transaction, the 24.99% membership interest in Rockies Express was transferred to the Partnership at TD's historical carrying amount, including the remaining unamortized basis difference driven by the difference between the fair value of the investment and the book value of the underlying assets and liabilities on November 13, 2012, the date of acquisition by TD. For additional information, see Note 7 – Investments in Unconsolidated Affiliates.

As of March 31, 2017, the negative basis difference carried over from TD was approximately $386.8 million. 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 associated with the recently acquired 24.99% membership interest in Rockies Express at June 30, 2017 was allocated as follows:

	Basis Difference (in thousands)	Amortization Period
Long-term debt	$19,291	2 - 25 years
Property, plant and equipment	(402,984)	35 years
Total basis difference	$(383,693)	

Acquisition of Tallgrass Terminals, LLC and Tallgrass NatGas Operator, LLC

Effective January 1, 2017, we acquired 100% of the issued and outstanding membership interests in Terminals and 100% of the issued and outstanding membership interests in NatGas from TD for total cash consideration of $140 million. These acquisitions are considered transactions between entities under common control, and a change in reporting entity.

Terminals owns several fully operational assets providing storage capacity and additional injection points for the Pony Express System, including the Sterling Terminal near Sterling, Colorado, the Buckingham Terminal in northeast Colorado, and a 20% interest in the Deeprock Development Terminal in Cushing, Oklahoma. Our 20% membership interest in Deeprock Development as of June 30, 2017 and December 31, 2016 is recorded under the equity method of accounting and reported as "Unconsolidated investments" on our condensed consolidated balance sheets. As discussed in Note 15 – Subsequent Events, Terminals acquired an additional 49% membership interest in Deeprock Development in July 2017. Terminals also owns acreage in Cushing, Oklahoma and Guernsey, Wyoming, which is under development to provide additional storage capacity, and other potential opportunities.

NatGas is the operator of the Rockies Express Pipeline and receives a fee from Rockies Express as compensation for its services.

Historical Financial Information

The results of our acquisitions of Terminals and NatGas are included in the condensed consolidated balance sheets as of June 30, 2017 and December 31, 2016. The following table presents our previously reported December 31, 2016 condensed consolidated balance sheet, adjusted for the acquisitions of Terminals and NatGas:

	December 31, 2016			
	TEP (As previously reported)	Consolidate Terminals	Consolidate NatGas	TEP (As currently reported)
	(in thousands)			
ASSETS				
Current Assets:				
Cash and cash equivalents	$1,873	$ —	$ —	$1,873
Accounts receivable, net	59,469	38	29	59,536
Gas imbalances	1,597	—	—	1,597
Inventories	12,805	288	—	13,093
Derivative assets	10,967	—	—	10,967
Prepayments and other current assets	6,820	808	—	7,628
Total Current Assets	93,531	1,134	29	94,694
Property, plant and equipment, net	2,012,263	66,969	—	2,079,232
Goodwill	343,288	—	—	343,288
Intangible asset, net	93,522	—	—	93,522
Unconsolidated investments	461,915	13,710	—	475,625
Deferred financing costs, net	4,815	—	—	4,815
Deferred charges and other assets	9,637	1,400	—	11,037
Total Assets	$3,018,971	$ 83,213	$ 29	$3,102,213
LIABILITIES AND EQUITY				
Current Liabilities:				
Accounts payable	$24,076	$ 46	$ —	$24,122
Accounts payable to related parties	5,879	56	—	5,935
Gas imbalances	1,239	—	—	1,239
Derivative liabilities	556	—	—	556
Accrued taxes	16,328	668	—	16,996
Accrued liabilities	16,525	177	—	16,702
Deferred revenue	60,757	—	—	60,757
Other current liabilities	6,446	—	—	6,446
Total Current Liabilities	131,806	947	—	132,753
Long-term debt, net	1,407,981	—	—	1,407,981
Other long-term liabilities and deferred credits	7,063	—	—	7,063
Total Long-term Liabilities	1,415,044	—	—	1,415,044
Equity:				
Net Equity	1,472,121	82,266	29	1,554,416
Total Equity	1,472,121	82,266	29	1,554,416
Total Liabilities and Equity	$3,018,971	$ 83,213	$ 29	$3,102,213

The results of our acquisitions of Terminals and NatGas are included in the condensed consolidated statements of income for the three and six months ended June 30, 2017 and 2016. The following tables present the previously reported condensed consolidated statements of income for the three and six months ended June 30, 2016, adjusted for the acquisitions of Terminals and NatGas:

	Three Months Ended June 30, 2016				
	TEP (As previously reported)	Consolidate Terminals	Consolidate NatGas	Elimination (1)	TEP (As currently reported)
	(in thousands)				
Revenues:					
Crude oil transportation services	$93,322	$ —	$ —	$ —	$93,322
Natural gas transportation services	28,682	—	—	—	28,682
Sales of natural gas, NGLs, and crude oil	16,830	—	—	—	16,830
Processing and other revenues	8,097	2,957	1,992	(2,865)	10,181
Total Revenues	146,931	2,957	1,992	(2,865)	149,015
Operating Costs and Expenses:					
Cost of sales (exclusive of depreciation and amortization shown below)	15,958	—	—	—	15,958
Cost of transportation services (exclusive of depreciation and amortization shown below)	14,240	200	—	(2,865)	11,575
Operations and maintenance	13,864	406	—	—	14,270
Depreciation and amortization	21,576	314	—	—	21,890
General and administrative	13,909	413	—	—	14,322
Taxes, other than income taxes	5,639	144	—	—	5,783
Contract termination	—	8,061 (2)	—	—	8,061
Loss on disposal of assets	1,849	—	—	—	1,849
Total Operating Costs and Expenses	87,035	9,538	—	(2,865)	93,708
Operating Income (Loss)	59,896	(6,581)	1,992	—	55,307
Other Income (Expense):					
Interest expense, net	(9,233)	—	—	—	(9,233)
Unrealized gain on derivative instrument	18,953	—	—	—	18,953
Equity in earnings of unconsolidated investments	23,321	701	—	—	24,022
Other income, net	221	—	—	—	221
Total Other Income	33,262	701	—	—	33,963
Net income (loss)	93,158	(5,880)	1,992	—	89,270
Net income attributable to noncontrolling interests	(1,110)	—	—	—	(1,110)
Net income (loss) attributable to partners	$92,048	$ (5,880)	$ 1,992	$ —	$88,160

	Six Months Ended June 30, 2016				
	TEP (As previously reported)	Consolidate Terminals	Consolidate NatGas	Elimination [(1)]	TEP (As currently reported)
	(in thousands)				
Revenues:					
Crude oil transportation services	$187,894	$ —	$ —	$ —	$187,894
Natural gas transportation services	57,962	—	—	—	57,962
Sales of natural gas, NGLs, and crude oil	30,756	—	—	—	30,756
Processing and other revenues	15,724	5,866	3,673	(5,692)	19,571
Total Revenues	292,336	5,866	3,673	(5,692)	296,183
Operating Costs and Expenses:					
Cost of sales (exclusive of depreciation and amortization shown below)	29,526	—	—	—	29,526
Cost of transportation services (exclusive of depreciation and amortization shown below)	30,396	400	—	(5,692)	25,104
Operations and maintenance	26,341	887	—	—	27,228
Depreciation and amortization	43,268	629	—	—	43,897
General and administrative	26,925	887	—	—	27,812
Taxes, other than income taxes	13,145	288	—	—	13,433
Contract termination	—	8,061 [(2)]	—	—	8,061
Loss on disposal of assets	1,849	—	—	—	1,849
Total Operating Costs and Expenses	171,450	11,152	—	(5,692)	176,910
Operating Income (Loss)	120,886	(5,286)	3,673	—	119,273
Other Income (Expense):					
Interest expense, net	(16,732)	—	—	—	(16,732)
Unrealized gain on derivative instrument	10,007	—	—	—	10,007
Equity in earnings of unconsolidated investments	23,321	1,410	—	—	24,731
Other income, net	787	—	—	—	787
Total Other Income	17,383	1,410	—	—	18,793
Net income (loss)	138,269	(3,876)	3,673	—	138,066
Net income attributable to noncontrolling interests	(2,151)	—	—	—	(2,151)
Net income (loss) attributable to partners	$136,118	$ (3,876)	$ 3,673	$ —	$135,915

(1) Represents the elimination of revenue and cost of transportation services associated with the lease of the Sterling Terminal facilities by Pony Express.

(2) Represents a one-time charge related to the termination of an operating agreement at the Sterling Terminal.

4. Related Party Transactions

As a result of our relationship with TD and its affiliates, we have entered into a number of related party transactions. The following disclosure includes those related party transactions which are not otherwise disclosed in these notes to our condensed consolidated financial statements.

We have no employees. In connection with the closing of our initial public offering on May 17, 2013, TEP and its general partner entered into an Omnibus Agreement with TD and certain of its affiliates, including Tallgrass Operations, LLC (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.

Totals of transactions with affiliated companies, excluding transactions disclosed elsewhere in these notes, are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands)			
Cost of transportation services [1]	$4,907	$4,829	$9,414	$9,258
Charges to TEP: [2]				
Property, plant and equipment, net	$510	$649	$803	$1,567
Operations and maintenance	$7,430	$6,373	$13,707	$12,557
General and administrative	$10,935	$10,439	$20,312	$19,651

(1) Reflects rent expense for the crude oil storage at the Deeprock Terminal.

(2) Charges to TEP 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, 2017	December 31, 2016
	(in thousands)	
Receivable from related parties:		
Rockies Express Pipeline LLC	$1,029	$ 590
Total receivable from related parties	$1,029	$ 590
Accounts payable to related parties:		
Tallgrass Operations, LLC	$5,817	$ 5,854
Tallgrass Equity, LLC	78	68
Deeprock Development, LLC	—	13
Total accounts payable to related parties	$5,895	$ 5,935

Gas imbalances with affiliated shippers are as follows:

	June 30, 2017	December 31, 2016
	(in thousands)	
Affiliate gas imbalance receivables	$—	$ 177
Affiliate gas imbalance payables	$205	$ —

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5. Inventory

The components of inventory at June 30, 2017 and December 31, 2016 consisted of the following:

	June 30, 2017	December 31, 2016
	(in thousands)	
Crude oil	$2,909	$ 5,462
Materials and supplies	6,366	6,383
Natural gas liquids	413	265
Gas in underground storage	1,553	983
Total inventory	$11,241	$ 13,093

6. Property, Plant and Equipment

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

	June 30, 2017	December 31, 2016
	(in thousands)	
Crude oil pipelines	$1,218,337	$1,202,125
Natural gas pipelines	572,749	572,150
Gathering, processing and treating assets (1)	401,186	256,901
General and other	253,508	223,310
Construction work in progress	22,513	20,606
Accumulated depreciation and amortization	(235,539)	(195,860)
Total property, plant and equipment, net	$2,232,754	$2,079,232

(1) Includes approximately $138.2 million of assets associated with the Douglas Gathering System acquired in June 2017.

7. Investments in Unconsolidated Affiliates

Rockies Express

Our investment in Rockies Express is recorded under the equity method of accounting and is reported as "Unconsolidated investments" on our condensed consolidated balance sheets. During the six months ended June 30, 2017, we recognized equity in earnings associated with our 49.99% membership interest in Rockies Express of $62.1 million, inclusive of the amortization of the negative basis difference, and received distributions from and made contributions to Rockies Express of $89.4 million and $17.8 million, respectively. As discussed in Note 3 – Acquisitions, we acquired an additional 24.99% membership interest in Rockies Express from TD on March 31, 2017.

Summarized financial information for Rockies Express is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands)			
Revenue	$207,149	$175,350	$408,487	$391,902
Operating income	$112,703	$85,352	$220,072	$201,411
Net income to Members	$70,945	$112,728	$137,195	$192,663

8. 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, 2017	December 31, 2016
		(in thousands)	
Crude oil derivative contracts (1)	Current assets	$207	$—
Natural gas derivative contracts (2)	Current assets	$13	$291
Call option derivative (3)	Current assets	$—	$10,676
Crude oil derivative contracts (1)	Current liabilities	$—	$440
Natural gas derivative contracts (2)	Current liabilities	$—	$116

(1) The fair value shown for crude oil derivative contracts represents the sale of 30,000 barrels and 125,000 barrels of crude oil as of June 30, 2017 and December 31, 2016, respectively, which will settle throughout 2017.

(2) As of June 30, 2017, the fair value shown for natural gas derivative contracts was comprised of derivative volumes for long natural gas fixed-price swaps totaling 0.2 Bcf. As of December 31, 2016, the fair value shown for natural gas derivative contracts was comprised of derivative volumes for short and long natural gas fixed-price swaps totaling 0.3 Bcf and 0.4 Bcf, respectively.

(3) As discussed below, 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 covering the 6,518,000 common units issued to TD. As of February 1, 2017, no common units remained subject to the call option.

Effect of Derivative Contracts in the Statements of Income

The following table summarizes the impact of derivative contracts not designated as hedging contracts for the three and six months ended June 30, 2017 and 2016:

Contract Type	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,	
		2017	2016	2017	2016
		(in thousands)			
Crude oil derivative contracts	Sales of natural gas, NGLs, and crude oil	$ 227	$ 148	$ 890	$ 148
Natural gas derivative contracts	Sales of natural gas, NGLs, and crude oil	$ (67)	$ (307)	$ 106	$ (351)
Call option derivative	Unrealized gain on derivative instrument	$ —	$ 18,953	$ 1,885	$ 10,007

Call Option Derivative

As part of our acquisition of an additional 31.3% membership interest in Pony Express effective January 1, 2016, TD granted us an 18 month call option at an exercise price of $42.50 per common unit covering the 6,518,000 common units issued to TD as a portion of the consideration. In July 2016 and October 2016, we partially exercised the call option covering 3,563,146 and 1,251,760 common units, respectively, for cash payments of $151.4 million and $53.2 million, respectively. On February 1, 2017, we exercised the remainder of the call option covering an additional 1,703,094 common units for a cash payment of $72.4 million. These common units were deemed canceled upon the exercise of the call option and as of the applicable exercise date were no longer issued and outstanding.

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 was TD.

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. The maximum potential exposure to credit losses on our crude oil and natural gas derivative contracts at June 30, 2017 was:

	Asset Position (in thousands)
Gross	$ 220
Netting agreement impact	—
Cash collateral held	—
Net exposure	$ 220

As of June 30, 2017 and December 31, 2016, 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 our commodity derivative contracts nor did we have any margin deposits with counterparties associated with our commodity derivative contracts.

Fair Value

Derivative assets and liabilities are measured and reported at fair value. Derivative contracts can be exchange-traded or over-the-counter ("OTC"). OTC commodity 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. The call option granted by TD was 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 was classified within Level 2 of the fair value hierarchy as the value was based on significant observable inputs.

The following table summarizes the fair value measurements of our derivative contracts as of June 30, 2017 and December 31, 2016 based on the fair value hierarchy:

	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, 2017:				
Crude oil derivative contracts	$207	$ —	$ 207	$ —
Natural gas derivative contracts	$13	$ —	$ 13	$ —
As of December 31, 2016:				
Call option derivative	$10,676	$ —	$ 10,676	$ —
Natural gas derivative contracts	$291	$ —	$ 291	$ —

	Total	Liability 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 December 31, 2016:				
Crude oil derivative contracts	$440	$ —	$ 440	$ —
Natural gas derivative contracts	$116	$ —	$ 116	$ —

9. Long-term Debt

Long-term debt consisted of the following at June 30, 2017 and December 31, 2016:

	June 30, 2017	December 31, 2016
	(in thousands)	
Revolving credit facility	$1,348,000	$1,015,000
5.50% senior notes due September 15, 2024	750,000	400,000
Less: Deferred financing costs, net [1]	(10,432)	(7,019)
Total long-term debt, net	$2,087,568	$1,407,981

(1) Deferred financing costs, net as presented above relate solely to the 2024 Notes. Deferred financing costs associated with our revolving credit facility are presented in noncurrent assets on our condensed consolidated balance sheets.

Senior Unsecured Notes

On September 1, 2016, TEP and Tallgrass Energy Finance Corp. (the "Co-Issuer" and together with TEP, the "Issuers"), the Guarantors named therein and U.S. Bank, National Association, as trustee, entered into an Indenture dated September 1, 2016 (the "Indenture"), pursuant to which the Issuers issued $400 million in aggregate principal amount of 5.50% senior notes due 2024 (the "2024 Notes"). On May 16, 2017, the Issuers issued an additional $350 million in aggregate principal amount of the 2024 Notes which are also governed by the Indenture. The notes issued on September 1, 2016 and May 16, 2017 are treated as a single class of debt securities and have identical terms, other than the issue date, offering price and first interest payment date.

The Indenture contains covenants that, among other things, limit TEP's ability and the ability of its restricted subsidiaries to: (i) incur, assume or guarantee additional indebtedness or issue preferred units; (ii) create liens to secure indebtedness; (iii) pay distributions on equity interests, repurchase equity securities or redeem subordinated securities; (iv) make investments; (v) restrict distributions, loans or other asset transfers from TEP's restricted subsidiaries; (vi) consolidate with or merge with or into, or sell substantially all of TEP's properties to, another person; (vii) sell or otherwise dispose of assets, including equity interests in subsidiaries; and (viii) enter into transactions with affiliates. As of June 30, 2017, we are in compliance with the covenants required under the 2024 Notes.

Revolving Credit Facility

On June 2, 2017, TEP entered into a $1.75 billion Second Amended and Restated Credit Agreement with Wells Fargo Bank, National Association, as administrative agent and collateral agent, and a syndicate of lenders (the "Amended Credit Agreement"). The Amended Credit Agreement amends and restates TEP's existing revolving credit facility. The Amended Credit Agreement, among other things, extends the maturity date of TEP's existing revolving credit facility from May 13, 2018 to June 2, 2022, and provides for an uncommitted accordion in an amount up to an additional $250 million, subject to the satisfaction of certain other conditions. In addition, the revolving credit facility includes a $60 million sublimit for swing line loans and a $75 million sublimit for letters of credit.

The following table sets forth the available borrowing capacity under the revolving credit facility as of June 30, 2017 and December 31, 2016:

	June 30, 2017	December 31, 2016
	(in thousands)	
Total capacity under the revolving credit facility	$1,750,000	$1,750,000
Less: Outstanding borrowings under the revolving credit facility	(1,348,000)	(1,015,000)
Less: Letters of credit issued under the revolving credit facility	(60)	—
Available capacity under the revolving credit facility	$401,940	$735,000

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 therefrom, 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 5.00 to 1.00 (which will be increased to 5.50 to 1.00 for certain measurement periods following the consummation of certain acquisitions), a consolidated senior secured leverage ratio of not more than 3.75 to 1.00 and a consolidated interest coverage ratio of not less than 2.50 to 1.00. As of June 30, 2017, 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 0.250% to 0.500%, based on our total leverage ratio. As of June 30, 2017, the weighted average interest rate on outstanding borrowings under the revolving credit facility was 2.92%. During the six months ended June 30, 2017, our weighted average effective interest rate, including the interest on outstanding borrowings under the revolving credit facility, commitment fees, and amortization of deferred financing costs, was 3.17%.

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, 2017 and December 31, 2016, 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)				
As of June 30, 2017:					
Revolving credit facility	$—	$ 1,348,000	$ —	$1,348,000	$1,348,000
2024 Notes	$—	$ 763,695	$ —	$763,695	$739,568
As of December 31, 2016:					
Revolving credit facility	$—	$ 1,015,000	$ —	$1,015,000	$1,015,000
2024 Notes	$—	$ 398,000	$ —	$398,000	$392,981

The long-term debt borrowed under the revolving credit facility is carried at amortized cost. As of June 30, 2017 and December 31, 2016, the fair value of borrowings under the revolving credit facility approximates the carrying amount of the borrowings using a discounted cash flow analysis. The 2024 Notes are carried at amortized cost, net of deferred financing costs. The estimated fair value of the 2024 Notes is based upon quoted market prices adjusted for illiquid markets. We are not aware of any factors that would significantly affect the estimated fair value subsequent to June 30, 2017.

10. Partnership Equity and Distributions

Equity Distribution Agreements

As of June 30, 2017, we had active equity distribution agreements 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 $100.2 million and $657.5 million. Net cash proceeds from any sale of the common units may be used for general partnership purposes, which includes, among other things, the Partnership's exercise of the call option with respect to the 6,518,000 common units issued 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, 2017, we issued and sold 2,341,061 common units with a weighted average sales price of $48.82 per unit under our equity distribution agreements for net cash proceeds of approximately $112.8 million (net of approximately $1.5 million in commissions and professional service expenses). We used the net cash proceeds for general partnership purposes as described above.

Repurchase of Common Units Owned by TD

Following an offer received from TD with respect to common units owned by TD not subject to the call option, we repurchased 736,262 common units from TD at an aggregate price of approximately $35.3 million, or $47.99 per common unit, on February 1, 2017, which was approved by the conflicts committee of the board of directors of our general partner. These common units were deemed canceled upon our purchase and as of such transaction date were no longer issued and outstanding.

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

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 Common Unit
		(in thousands, except per unit amounts)				
June 30, 2017	August 14, 2017 [1]	$67,671	$36,342	$1,186	$105,199	$ 0.9250
March 31, 2017	May 15, 2017	60,486	29,840	1,040	91,366	0.8350
December 31, 2016	February 14, 2017	58,793	28,358	1,008	88,159	0.8150
September 30, 2016	November 14, 2016	57,332	26,987	976	85,295	0.7950
June 30, 2016	August 12, 2016	54,442	24,262	911	79,615	0.7550
March 31, 2016	May 13, 2016	48,238	19,816	830	68,884	0.7050

(1) The distribution announced on July 5, 2017 for the second quarter of 2017 will be paid on August 14, 2017 to unitholders of record at the close of business on July 28, 2017.

Other Contributions and Distributions

During the six months ended June 30, 2017, TEP recognized the following other contributions and distributions:

- TEP was deemed to have made a noncash capital distribution of $57.7 million to the general partner, which represents the excess purchase price over the carrying value of the Terminals and NatGas net assets acquired January 1, 2017;
- TEP was deemed to have made a noncash capital distribution of $12.6 million to the general partner, which represents the derecognition of a portion of the derivative asset associated with the partial exercise of the call option;
- TEP was deemed to have received a noncash capital contribution of $63.7 million from the general partner, which represents the excess carrying value of the additional 24.99% membership interest in Rockies Express acquired March 31, 2017 over the fair value of the consideration paid;
- TEP received contributions from TD of $2.3 million, primarily to indemnify TEP for costs associated with Trailblazer's Pipeline Integrity Management Program, as discussed in Note 13 – Legal and Environmental Matters; and
- TEP recognized contributions from and distributions to noncontrolling interests of $0.9 million and $2.8 million, respectively, which primarily consisted of activity associated with TD's 2% noncontrolling interest in Pony Express.

During the six months ended June 30, 2016, TEP recognized the following other contributions and distributions:

- 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; and
- TEP recognized contributions from and distributions to noncontrolling interests of $7.3 million and $3.3 million, respectively, which primarily consisted of activity associated with TD's 2% noncontrolling interest in Pony Express.

11. Net Income per Limited Partner Unit

The Partnership's net income is allocated to the general partner and the limited partners 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.
All net income or loss from Terminals and NatGas prior to its acquisition on January 1, 2017 is allocated to predecessor operations in the condensed consolidated statements of income and in the table below. Historical earnings of transferred businesses for periods prior to the date of those common control transactions are solely those of the general partner, and therefore we have appropriately excluded any allocation to the limited partner units when determining net income available to common unitholders. We present the financial results of any transferred business prior to the transaction date in the line item "Predecessor operations interest in net loss" in the condensed consolidated statements of income and in the table below.
The following table illustrates the Partnership's calculation of net income per common unit for the three and six months ended June 30, 2017 and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(in thousands, except per unit amounts)			
Net income	$90,829	$89,270	$162,613	$138,066
Net income attributable to noncontrolling interests	(949)	(1,110)	(1,828)	(2,151)
Net income attributable to partners	89,880	88,160	160,785	135,915
Predecessor operations interest in net loss	—	3,888	—	203
General partner interest in net income	(37,301)	(25,320)	(67,884)	(45,673)
Net income available to common unitholders	$52,579	$66,728	$92,901	$90,445
Basic net income per common unit	$0.72	$0.93	$1.28	$1.30
Diluted net income per common unit	$0.72	$0.92	$1.27	$1.29
Basic average number of common units outstanding	72,618	71,975	72,581	69,471
Equity Participation Unit equivalent units	444	950	391	889
Diluted average number of common units outstanding	73,062	72,925	72,972	70,360

12. Regulatory Matters
There are no regulatory proceedings challenging the rates of Pony Express, Rockies Express, Tallgrass Interstate Gas Transmission, LLC ("TIGT") or Trailblazer Pipeline Company LLC ("Trailblazer"). We have made certain regulatory filings with the FERC, including the following:
Pony Express
On May 22, 2017 and May 31, 2017, Pony Express made tariff filings with the FERC in Docket Nos. IS17-263-000, IS17-464-00, and IS17-465-000 to increase the contract and non-contract rates by an amount reflecting the most recent FERC annual index adjustment of approximately 0.2%, which became effective July 1, 2017.
Rockies Express
Rockies Express Zone 3 Capacity Enhancement Project – FERC Docket No. CP15-137-000
On March 31, 2015 in Docket No. CP15-137-000, Rockies Express filed with the 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 facilities increased the Rockies Express Zone 3 east-to-west mainline capacity by 0.8 Bcf/d. 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. The project was placed in-service for the 0.8 Bcf/d on January 6, 2017.
2016 Annual and Interim FERC Fuel Tracking Filings - FERC Docket Nos. RP16-702 and RP17-240
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. On December 1, 2016, Rockies Express made an interim fuel tracker filing with a proposed effective date of January 1, 2017 in Docket No. RP17-240. The FERC issued an order accepting the filing on December 29, 2016.
Electric Power Charge Clarification - FERC Docket No. RP17-285
On December 21, 2016, in Docket No. RP17-285, Rockies Express proposed certain revisions to the General Terms and Conditions of its tariff to clarify that the electric power costs associated with the operation of gas coolers installed in association with the Zone 3 Capacity Enhancement Project, at both electric and gas powered stations, will be included in the Power Cost Tracker. Several shippers submitted comments on the proposal. The FERC issued an order on January 19, 2017 accepting the proposed revisions permitting the recovery of electric power costs from the operation of both gas and electric powered compressor stations, subject to certain clarifications.
2017 Annual FERC Fuel Tracking Filing - FERC Docket No. RP17-401-000
On February 13, 2017, in Docket No. RP17-401-000, Rockies Express made its annual fuel and power cost tracker filing with a proposed effective date of April 1, 2017. The FERC issued an order accepting the filing, including certain requested waivers, on March 21, 2017.
TIGT
General Rate Case Filing - FERC Docket No. RP16-137-000, et seq.
On October 30, 2015, TIGT filed a general rate case with the FERC pursuant to Section 4 of the National Gas Act ("NGA"). The rate case proposed, among other things, a general system-wide increase in the maximum tariff rates for all firm and interruptible services offered by TIGT, certain changes to the transportation rate design of its system, a fixed fuel and lost and unaccounted for ("FL&U") and power cost tracker, and certain pro forma tariff records reflecting revisions to TIGT's Tariff.
On June 8, 2016, TIGT filed an Offer of Settlement (the "TIGT Rate Case Settlement") with the FERC, which resolved all issues the FERC had set for hearing. Following certification by the Administrative Law Judge and approval by the FERC, TIGT filed revised tariff records to implement the TIGT Rate Case Settlement, which the FERC subsequently approved on December 23, 2016. Per the terms of the TIGT Rate Case Settlement, TIGT is required to file a new general rate case on May 1, 2019 (provided that such rate case is not pre-empted by a pre-filing settlement).

On February 3, 2017, the FERC accepted TIGT's pro forma tariff records, subject to conditions, and directed TIGT to file the actual tariff records within 30 days. TIGT subsequently submitted a compliance filing to implement the actual tariff records and restate its tariff to be effective April 1, 2017 and also filed to cancel its existing tariff (which was ultimately superseded by the new tariff). On March 16, 2017, the FERC accepted both filings.

2017 Annual Fuel Tracker Filing - FERC Docket No. RP17-428-000

On February 27, 2017, TIGT made its annual fuel tracker filing with a proposed effective date of April 1, 2017 in Docket No. RP17-428-000. The filing incorporated the FL&U tracker and power cost tracker mechanisms agreed to in the TIGT Rate Case Settlement. The FERC accepted the filing on March 21, 2017.

Trailblazer

2017 Annual Fuel Tracker Filing - FERC Docket No. RP17-549-000

On March 22, 2017, Trailblazer made its annual fuel tracker filing with a proposed effective date of May 1, 2017 in Docket No. RP17-549. The FERC accepted the filing on April 19, 2017.

13. 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, have recorded no reserve for legal claims as of June 30, 2017 or December 31, 2016.

Rockies Express

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, seeking approximately $303 million in damages and other relief. 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, which operated as a stay of the Harris County state court proceeding.

On January 12, 2017, Rockies Express and Ultra entered into an agreement to settle Rockies Express' approximately $303 million claim against Ultra. In accordance with the settlement agreement, Ultra made a cash payment to Rockies Express of $150 million on July 12, 2017, and entered into a new, seven-year firm transportation agreement with Rockies Express commencing December 1, 2019, for west-to-east service of 0.2 Bcf/d at a rate of approximately $0.37 per dth/d, or approximately $26.8 million annually. TEP received its proportionate distribution from the settlement in July 2017.

Michels Corporation

On June 17, 2014, Michels Corporation ("Michels") filed a complaint and request for relief against Rockies Express in the Court of Common Pleas, Monroe County, Ohio, as a result of work performed by Michels to construct the Seneca Lateral Pipeline in Ohio. Michels sought unspecified damages from Rockies Express and asserted claims of breach of contract, negligent misrepresentation, unjust enrichment and quantum meruit. Michels also filed notices of Mechanic's Liens in Monroe and Noble Counties, asserting $24.2 million as the amount due.

On February 2, 2017, Rockies Express and Michels agreed to resolve Michels' claims for a $10 million cash payment by Rockies Express. The cash payment was inclusive of approximately $5.9 million that Rockies Express had been withholding from Michels. Subsequently, Rockies Express and Michels entered into a definitive agreement with respect to the settlement and Rockies Express made the $10 million cash payment to Michels on February 16, 2017.

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 $7.2 million and $4.0 million at June 30, 2017 and December 31, 2016, 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

Trailblazer is currently operating at less than its current maximum allowable operating pressure ("MAOP"), public notice of which was first provided in June 2014. As a result of smart tool surveys in 2014, Trailblazer identified approximately 25 - 35 miles of pipe that will likely need to be repaired or replaced in order for the pipeline to operate at its MAOP of 1,000 pounds per square inch across all segments of the Trailblazer Pipeline. Such repair or replacement will likely occur over a period of years, depending upon the remediation and repair plan implemented by Trailblazer. Segments of the Trailblazer Pipeline that require full replacement could cost as much as $2.7 million per mile and repair costs on sections of the pipeline that do not require full replacement are expected to be less on a per mile basis. 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 us. With respect to the approximately 25 - 35 miles of pipe that has been identified, Trailblazer completed 32 excavation digs in 2015 at an aggregate cost of approximately $1.3 million.

Trailblazer completed additional excavation digs and replaced approximately 8 miles of pipe at an aggregate cost of approximately $19.0 million during 2016, and intends to complete final remediation and cleanup of this pipe replacement project in 2017 at an estimated cost of $2.5 million. Trailblazer is currently exploring all possible cost recovery options to recover such out of pocket costs, including recovery through a general rate increase, negotiated rate agreements with its customers, or other FERC-approved recovery mechanisms.

In connection with our acquisition of the Trailblazer Pipeline, TD agreed to contractually indemnify TEP for certain out of pocket costs related to repairing or remediating the Trailblazer Pipeline, to the extent that such actions were necessitated by external corrosion caused by the pipeline's disbonded Hi-Melt CTE coating. The contractual indemnity provided by TD was capped at $20 million and was subject to a $1.5 million deductible. TEP has received $20 million from TD pursuant to the contractual indemnity as of June 30, 2017.

Pony Express

Pipeline Integrity

In connection with certain crack tool runs on the Pony Express System completed in 2015 and 2016, Pony Express completed approximately $9.8 million of remediation for anomalies identified on the Pony Express System associated with the initial conversion and commissioning of portions of the pipeline converted from natural gas to crude oil service, and expects to complete additional remediation in 2017 on the Pony Express System of approximately $9 million.

Terminals

System Failures

In January 2017, approximately 10,000 bbls of crude oil were released at the Sterling Terminal as the result of a defective roof drain system on a storage tank. The release was restricted to the containment area designed for such purpose and approximately 9,000 bbls were recovered. Remediation was complete as of June 30, 2017. The total cost to remediate the release was approximately $600,000.

14. Reportable Segments

Our operations are located in the United States. We are organized into three reportable 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, Denver-Julesburg and Powder River Basins, 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. The Crude Oil Transportation & Logistics segment also includes our 100% membership interest in Terminals acquired effective January 1, 2017.

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 an integrated natural gas storage facility 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 100% membership interest in NatGas acquired effective January 1, 2017 and our 49.99% membership interest in Rockies Express, including the additional 24.99% membership interest acquired effective March 31, 2017.

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. The Processing & Logistics segment also includes the Douglas Gathering system acquired on June 5, 2017.

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 and the 2024 Notes, 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:

Revenue:	Three Months Ended June 30, 2017			Three Months Ended June 30, 2016		
	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	External Revenue
	(in thousands)					
Crude Oil Transportation & Logistics	$96,052	$—	$96,052	$93,562	$—	$93,562
Natural Gas Transportation & Logistics	33,110	(1,442)	31,668	32,142	(1,410)	30,732
Processing & Logistics	33,143	—	33,143	24,721	—	24,721
Corporate and Other	—	—	—	—	—	—
Total revenue	$162,305	$(1,442)	$160,863	$150,425	$(1,410)	$149,015

Revenue:	Six Months Ended June 30, 2017			Six Months Ended June 30, 2016		
	Total Revenue	Inter-Segment	External Revenue	Total Revenue	Inter-Segment	External Revenue
	(in thousands)					
Crude Oil Transportation & Logistics	$181,144	$—	$181,144	$188,216	$—	$188,216
Natural Gas Transportation & Logistics	69,538	(2,887)	66,651	64,810	(2,765)	62,045
Processing & Logistics	57,468	—	57,468	45,922	—	45,922
Corporate and Other	—	—	—	—	—	—
Total revenue	$308,150	$(2,887)	$305,263	$298,948	$(2,765)	$296,183

Adjusted EBITDA:	Three Months Ended June 30, 2017 Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA	Three Months Ended June 30, 2016 Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA
	(in thousands)					
Crude Oil Transportation & Logistics	$65,457	$1,345	$66,802	$60,375	$1,346	$61,721
Natural Gas Transportation & Logistics	79,090	(1,442)	77,648	47,755	(1,410)	46,345
Processing & Logistics	9,322	97	9,419	3,549	64	3,613
Corporate and Other	(2,917)	—	(2,917)	(1,089)	—	(1,089)
Reconciliation to Net Income:						
Add:						
Equity in earnings of unconsolidated investments			42,741			24,022
Non-cash (loss) gain related to derivative instruments, net of noncontrolling interest			(84)			18,791
Less:						
Interest expense, net of noncontrolling interest			(19,688)			(9,233)
Depreciation and amortization expense, net of noncontrolling interest			(22,555)			(22,354)
Distributions from unconsolidated investments			(59,863)			(30,338)
Non-cash compensation expense			(1,494)			(1,469)
Loss on disposal of assets			(129)			(1,849)
Net income attributable to partners			$89,880			$88,160

Adjusted EBITDA:	Six Months Ended June 30, 2017 Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA	Six Months Ended June 30, 2016 Total Adjusted EBITDA	Inter-Segment	External Adjusted EBITDA
	(in thousands)					
Crude Oil Transportation & Logistics	$123,224	$2,689	$125,913	$127,360	$2,691	$130,051
Natural Gas Transportation & Logistics	132,120	(2,887)	129,233	66,588	(2,765)	63,823
Processing & Logistics	15,397	198	15,595	6,900	74	6,974
Corporate and Other	(4,678)	—	(4,678)	(2,441)	—	(2,441)
Reconciliation to Net Income:						
Add:						
Equity in earnings of unconsolidated investments			63,479			24,731
Non-cash gain related to derivative instruments, net of noncontrolling interests			2,357			9,801
Less:						
Interest expense, net of noncontrolling interest			(34,377)			(16,732)
Depreciation and amortization expense, net of noncontrolling interest			(44,422)			(44,836)
Distributions from unconsolidated investments			(90,682)			(30,972)
Non-cash compensation expense			(2,952)			(2,635)
Gain (loss) on disposal of assets			1,319			(1,849)
Net income attributable to partners			$160,785			$135,915

Capital Expenditures:	Six Months Ended June 30, 2017	2016
	(in thousands)	
Crude Oil Transportation & Logistics	$22,340	$25,529
Natural Gas Transportation & Logistics	8,368	4,115
Processing & Logistics	23,287	5,216
Corporate and Other	—	—
Total capital expenditures	$53,995	$34,860

Assets:	June 30, 2017	December 31, 2016
	(in thousands)	
Crude Oil Transportation & Logistics	$1,483,361	$1,493,866
Natural Gas Transportation & Logistics	1,624,714	1,176,147
Processing & Logistics	583,963	411,999
Corporate and Other	16,288	20,201
Total assets	$3,708,326	$3,102,213

15. Subsequent Events

Ultra Settlement

On July 12, 2017, Rockies Express received the $150 million settlement payment from Ultra as discussed in Note 13 – Legal and Environmental Matters.

Acquisition of Additional Interest in Deeprock Development

In July 2017, Terminals acquired an additional 49% membership interest in Deeprock Development, bringing Terminals' membership interest in Deeprock Development to 69%. On July 20, 2017, Terminals closed on the acquisition of an additional 40% membership interest in Deeprock Development from Kinder Morgan Cushing LLC for cash consideration of approximately $57.3 million. On July 21, 2017, Terminals closed the acquisition of an additional 9% membership interest in Deeprock Development from Deeprock Energy Resources LLC for total consideration valued at approximately $13.1 million, consisting of approximately $6.4 million in cash and the issuance of 128,790 common units (valued at approximately $6.7 million based on the July 20, 2017 closing price of TEP's common units).

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. As discussed further in Note 2 – Summary of Significant Accounting Policies to the accompanying condensed consolidated financial statements, our financial statements for historical periods prior to January 1, 2017 have been recast to reflect the operations of Terminals and NatGas, which were acquired effective January 1, 2017.

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, 2016 (our "2016 Form 10-K") filed with the United States Securities and Exchange Commission (the "SEC") on February 15, 2017.

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 the Douglas Gathering System in June 2017, our acquisition of an additional 24.99% membership interest in Rockies Express from TD in March 2017 and our acquisition of a 100% membership interest in NatGas and Terminals from TD in January 2017;
- the demand for our services, including crude oil transportation, storage and terminalling services, natural gas transportation, storage, gathering and processing services, and water business services as well as our ability to successfully contract or re-contract with our customers;
- large or multiple customer defaults, including defaults resulting from actual or potential insolvencies;
- our ability to successfully implement our business plan;
- changes in general economic conditions;
- competitive conditions in our industry;
- the effects of existing and future laws and governmental regulations;
- actions taken by third-party operators, processors and transporters;

- 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, natural gas liquids, and other hydrocarbons;
- 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, storing and terminalling crude oil, transporting, storing and processing natural gas, and transporting, gathering and disposing of water produced in connection with hydrocarbon exploration and production activities;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- natural disasters, weather-related delays, casualty losses and other matters beyond our control;
- interest rates;
- labor relations;
- changes in tax status;
- 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. Our operations are 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 and crude oil storage and terminalling facilities;
- 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 gathering, 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 5, 2017, the Board of Directors of our general partner declared a cash distribution for the quarter ended June 30, 2017 of $0.9250 per common unit. The distribution will be paid on August 14, 2017, to unitholders of record on July 28, 2017.

Ultra Settlement

On July 12, 2017, Rockies Express received the $150 million settlement payment from Ultra as discussed in Note 13 – Legal and Environmental Matters.

Acquisition of Additional Interest in Deeprock Development

In July 2017, Terminals acquired an additional 49% membership interest in Deeprock Development, bringing Terminals' membership interest in Deeprock Development to 69%. On July 20, 2017, Terminals closed on the acquisition of an additional 40% membership interest in Deeprock Development from Kinder Morgan Cushing LLC for cash consideration of approximately $57.3 million. On July 21, 2017, Terminals closed the acquisition of an additional 9% membership interest in Deeprock Development from Deeprock Energy Resources LLC for total consideration valued at approximately $13.1 million, consisting of approximately $6.4 million in cash and the issuance of 128,790 common units (valued at approximately $6.7 million based on the July 20, 2017 closing price of TEP's common units).

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, storage and terminalling 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 gather and 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 deficiency payments received from or utilized by our customers and preferred distributions received from Pony Express in excess of its distributable cash flow attributable to our net interest, 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, and are presented net of noncontrolling interest and reimbursements. We collect deficiency payments for volumes 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 customers' contractual transportation rights expire or the barrels are physically transported and delivered by 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,	
	2017	2016	2017	2016
	(in thousands)			
Reconciliation of Adjusted EBITDA to Net Income				
Net income attributable to partners	$89,880	$88,160	$160,785	$135,915
Add:				
Interest expense, net of noncontrolling interest	19,688	9,233	34,377	16,732
Depreciation and amortization expense, net of noncontrolling interest	22,555	22,354	44,422	44,836
Distributions from unconsolidated investments	59,863	30,338	90,682	30,972
Non-cash loss (gain) related to derivative instruments, net of noncontrolling interest	84	(18,791)	(2,357)	(9,801)
Non-cash compensation expense [(1)]	1,494	1,469	2,952	2,635
Loss (gain) from disposal of assets	129	1,849	(1,319)	1,849
Less:				
Equity in earnings of unconsolidated investments	(42,741)	(24,022)	(63,479)	(24,731)
Adjusted EBITDA	$150,952	$110,590	$266,063	$198,407
Reconciliation of Adjusted EBITDA and Distributable Cash Flow to Net Cash Provided by Operating Activities				
Net cash provided by operating activities	$137,610	$112,332	$241,851	$205,507
Add:				
Interest expense, net of noncontrolling interest	19,688	9,233	34,377	16,732
Other, including changes in operating working capital	(6,346)	(10,975)	(10,165)	(23,832)
Adjusted EBITDA	$150,952	$110,590	$266,063	$198,407
Add:				
Deficiency payments received, net	8,280	8,621	24,351	15,778
Cash flow attributable to predecessor operations	—	3,393	—	(732)

Less:				
Cash interest cost	(18,592)	(8,412)	(32,159)	(15,233)
Maintenance capital expenditures, net	(3,994)	(2,089)	(4,057)	(4,257)
Distributable Cash Flow	$136,646	$112,103	$254,198	$193,963

(1) Represents TEP's portion of non-cash compensation expense related to Equity Participation Units, excluding amounts allocated to TD.

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,	
	2017	2016	2017	2016
	(in thousands)			
Reconciliation of Adjusted EBITDA to Operating Income in the Crude Oil Transportation & Logistics Segment (1)				
Operating income	$51,774	$47,145	$96,489	$101,106
Add:				
Depreciation and amortization expense, net of noncontrolling interest	13,951	13,760	27,830	27,193
Distributions from unconsolidated investment	573	682	1,267	1,316
Other income, net	143	—	143	—
Less:				
Adjusted EBITDA attributable to noncontrolling interests	(1,000)	(1,067)	(1,871)	(2,110)
Non-cash loss (gain) related to derivative instruments, net of noncontrolling interest	16	(145)	(634)	(145)
Segment Adjusted EBITDA	$65,457	$60,375	$123,224	$127,360
Reconciliation of Adjusted EBITDA to Operating Income in the Natural Gas Transportation & Logistics Segment (1)				
Operating income	$14,726	$12,092	$32,894	$24,437
Add:				
Depreciation and amortization expense	4,792	5,479	9,575	11,357
Distributions from unconsolidated investment	59,290	29,656	89,415	29,656
Non-cash loss (gain) related to derivative instruments	—	307	(116)	351
Other income, net	282	221	352	787
Segment Adjusted EBITDA	$79,090	$47,755	$132,120	$66,588
Reconciliation of Adjusted EBITDA to Operating Income (Loss) in the Processing & Logistics Segment (1)				
Operating income (loss)	$5,262	$(1,372)	$9,378	$(1,194)
Add:				
Depreciation and amortization expense, net of noncontrolling interest	3,812	3,115	7,017	6,286
Non-cash loss related to derivative instruments	68	—	278	—
Loss (gain) on disposal of assets	129	1,849	(1,319)	1,849
Adjusted EBITDA attributable to noncontrolling interests	51	(43)	43	(41)
Segment Adjusted EBITDA	$9,322	$3,549	$15,397	$6,900
Total Segment Adjusted EBITDA	$153,869	$111,679	$270,741	$200,848
Corporate general and administrative costs	(2,917)	(1,089)	(4,678)	(2,441)
Total Adjusted EBITDA	$150,952	$110,590	$266,063	$198,407

(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 14 – Reportable Segments to the accompanying condensed consolidated financial statements.

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Results of Operations

The following provides a summary of our operating metrics for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Crude Oil Transportation & Logistics Segment:				
Crude oil transportation average contracted capacity (Bbls/d)	301,932	293,932	300,256	292,256
Crude oil transportation average throughput (Bbls/d)	273,732	286,217	267,851	288,746
Natural Gas Transportation & Logistics Segment:				
Gas transportation average firm contracted volumes (MMcf/d) [1]	1,495	1,639	1,603	1,637
Processing & Logistics Segment:				
Natural gas processing inlet volumes (MMcf/d)	105	106	104	102
Freshwater average volumes (Bbls/d)	107,776	26,857	86,265	31,108
Produced water gathering and disposal average volumes (Bbls/d)	16,561	19,384	13,161	15,356

(1) Volumes transported under firm fee contracts, excluding Rockies Express.

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,	
	2017	2016	2017	2016
	(in thousands)			
Revenues:				
Crude oil transportation services	$89,855	$93,322	$174,186	$187,894
Natural gas transportation services	29,429	28,682	61,114	57,962
Sales of natural gas, NGLs, and crude oil	22,918	16,830	38,299	30,756
Processing and other revenues	18,661	10,181	31,664	19,571
Total Revenues	160,863	149,015	305,263	296,183
Operating Costs and Expenses:				
Cost of sales (exclusive of depreciation and amortization shown below)	19,386	15,958	31,756	29,526
Cost of transportation services (exclusive of depreciation and amortization shown below)	14,758	11,575	28,261	25,104
Operations and maintenance	15,254	14,270	28,157	27,228
Depreciation and amortization	22,091	21,890	43,494	43,897
General and administrative	14,774	14,322	28,437	27,812
Taxes, other than income taxes	6,912	5,783	15,138	13,433
Contract termination	—	8,061	—	8,061
Loss (gain) on disposal of assets	184	1,849	(1,264)	1,849
Total Operating Costs and Expenses	93,359	93,708	173,979	176,910
Operating Income	67,504	55,307	131,284	119,273
Other Income (Expense):				
Interest expense, net	(19,688)	(9,233)	(34,377)	(16,732)
Unrealized gain on derivative instrument	—	18,953	1,885	10,007
Equity in earnings of unconsolidated investments	42,741	24,022	63,479	24,731
Other income, net	272	221	342	787
Total Other Income (Expense)	23,325	33,963	31,329	18,793
Net income	90,829	89,270	162,613	138,066
Net income attributable to noncontrolling interests	(949)	(1,110)	(1,828)	(2,151)
Net income attributable to partners	$89,880	$88,160	$160,785	$135,915
Other Financial Data:				
Adjusted EBITDA [1]	$150,952	$110,590	$266,063	$198,407

(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.

Three Months Ended June 30, 2017 Compared to the Three Months Ended June 30, 2016

Revenues. Total revenues were $160.9 million for the three months ended June 30, 2017, compared to $149.0 million for the three months ended June 30, 2016, which represents an increase of $11.8 million, or 8%, in total revenues. The overall increase in revenue was largely driven by increased revenues of $8.4 million, $2.5 million, and $1.0 million in the Processing & Logistics, Crude Oil Transportation & Logistics, and Natural Gas Transportation & Logistics segments, respectively, as discussed further below.

Operating costs and expenses. Operating costs and expenses were $93.4 million for the three months ended June 30, 2017 compared to $93.7 million for the three months ended June 30, 2016. The decrease in operating costs and expenses of $2.1 million and $1.7 million in the Crude Oil Transportation & Logistics and Natural Gas Transportation & Logistics segments, respectively, was partially offset by increased operating costs and expenses of $1.8 million in the Processing & Logistics segment, as discussed further below, as well as a $1.7 million increase in corporate general and administrative costs primarily due to payroll taxes associated with the vesting of common units associated with equity-based compensation grants under the general partner's Long-term Incentive Plan as well as legal costs associated with transactions during the three months ended June 30, 2017.

Interest expense, net. Interest expense of $19.7 million for the three months ended June 30, 2017 was primarily composed of interest and fees associated with our revolving credit facility and the 2024 Notes issued on September 1, 2016 and May 16, 2017. Interest expense of $9.2 million for the three months ended June 30, 2016 was 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 acquisitions of Terminals and NatGas effective January 1, 2017, a 24.99% membership interest in Rockies Express effective March 31, 2017, and the Douglas Gathering System on June 5, 2017, as well as the higher incremental borrowing rate on the 2024 Notes, the proceeds of which were used to repay borrowings under our revolving credit facility.

Unrealized gain on derivative instrument. Unrealized gain on derivative instrument of $19.0 million for the three months ended June 30, 2016 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 of February 1, 2017, no common units remained subject to the call option.

Equity in earnings of unconsolidated investments. Equity in earnings of unconsolidated investments was $42.7 million and $24.0 million for the three months ended June 30, 2017 and 2016, respectively. Equity in earnings of unconsolidated investments of $42.7 million for three months ended June 30, 2017 primarily reflects our portion of earnings and the amortization of a negative basis difference of $6.6 million associated with our 49.99% membership interest in Rockies Express, as well as $0.7 million related to our 20% membership interest in Deeprock Development during the three months ended June 30, 2017. Equity in earnings of unconsolidated investments of $24.0 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, as well as $0.7 million related to our 20% membership interest in Deeprock Development during the three months ended June 30, 2016. For additional information, see Note 7 – Investments in Unconsolidated Affiliates.

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, 2017 was $0.3 million compared to $0.2 million for the three months ended June 30, 2016.

Net income attributable to noncontrolling interests. Net income attributable to noncontrolling interests of $0.9 million for the three months ended June 30, 2017 compared to $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.

Six Months Ended June 30, 2017 Compared to the Six Months Ended June 30, 2016

Revenues. Total revenues were $305.3 million for the six months ended June 30, 2017, compared to $296.2 million for the six months ended June 30, 2016, which represents an increase of $9.1 million, or 3%, in total revenues. The overall increase in revenue was largely driven by increased revenues of $11.5 million and $4.7 million in the Processing & Logistics and Natural Gas Transportation & Logistics segments, respectively, partially offset by decreased revenues of $7.1 million in the Crude Oil Transportation & Logistics segment, as discussed further below.

Operating costs and expenses. Operating costs and expenses were $174.0 million for the six months ended June 30, 2017 compared to $176.9 million for the six months ended June 30, 2016, which represents a decrease of $2.9 million, or 2%. The overall decrease in operating costs and expenses is driven by decreased operating costs and expenses of $3.7 million and $2.5 million in the Natural Gas Transportation & Logistics and Crude Oil Transportation & Logistics segments, respectively, partially offset by increased operating costs and expenses of $1.0 million in the Processing & Logistics segment, as discussed further below, as well as a $2.4 million increase in corporate general and administrative costs primarily due to payroll taxes associated with the vesting of common units associated with equity-based compensation grants under the general partner's Long-term Incentive Plan, as well as legal costs associated with transactions during the six months ended June 30, 2017.

Interest expense, net. Interest expense of $34.4 million for the six months ended June 30, 2017 was primarily composed of interest and fees associated with our revolving credit facility and the 2024 Notes issued on September 1, 2016 and May 16, 2017. 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. The increase in interest and fees associated with our revolving credit facility is primarily due to increased borrowings to fund a portion of our 2016 acquisition of a 25% membership interest in Rockies Express and our recent acquisitions of Terminals and NatGas effective January 1, 2017, a 24.99% membership interest in Rockies Express effective March 31, 2017, and the Douglas Gathering System on June 5, 2017, as well as the higher incremental borrowing rate on the 2024 Notes, the proceeds of which were used to repay borrowings under our revolving credit facility.

Unrealized gain on derivative instrument. Unrealized gain on derivative instrument of $1.9 million and $10.0 million for the six months ended June 30, 2017 and 2016, respectively, 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 of February 1, 2017, no common units remained subject to the call option.

Equity in earnings of unconsolidated investments. Equity in earnings of unconsolidated investments was $63.5 million and $24.7 million for the six months ended June 30, 2017 and 2016, respectively. Equity in earnings of unconsolidated investments of $63.5 million for six months ended June 30, 2017 primarily reflects our portion of earnings and the amortization of a negative basis difference of $10.1 million associated with our 49.99% membership interest in Rockies Express, as well as $1.4 million related to our 20% membership interest in Deeprock Development during the six months ended June 30, 2017. Equity in earnings of unconsolidated investments of $24.7 million for the six months ended June 30, 2016 represents earnings associated with our acquisition of a 25% membership interest in Rockies Express effective May 6, 2016, as well as $1.4 million related to our 20% membership interest in Deeprock Development during the six months ended June 30, 2016. For additional information, see Note 7 – Investments in Unconsolidated Affiliates.

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, 2017 was $0.3 million compared to $0.8 million for the six months ended June 30, 2016. The decrease in other income was driven by lower income related to reimbursable projects at TIGT due to contract modifications.

Net income attributable to noncontrolling interests. Net income attributable to noncontrolling interests of $1.8 million for the six months ended June 30, 2017 compared to $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.

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,	
	2017	2016	2017	2016
	(in thousands)			
Revenues:				
Crude oil transportation services	$89,855	$93,322	$174,186	$187,894
Sales of natural gas, NGLs, and crude oil	6,007	148	6,670	148
Processing and other revenues	190	92	288	174
Total revenues	96,052	93,562	181,144	188,216
Operating costs and expenses:				
Cost of sales	5,449	—	5,449	—
Cost of transportation services	11,141	11,487	22,334	23,355
Operations and maintenance	3,767	3,616	7,517	7,928
Depreciation and amortization	13,480	13,287	26,887	26,241
General and administrative	5,048	5,749	10,577	11,257
Taxes, other than income taxes	5,393	4,217	11,891	10,268
Contract termination	—	8,061	—	8,061
Total operating costs and expenses	44,278	46,417	84,655	87,110
Operating income	$51,774	$47,145	$96,489	$101,106

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 14 – Reportable Segments to the accompanying condensed consolidated financial statements.

Three Months Ended June 30, 2017 Compared to the Three Months Ended June 30, 2016

Revenues. Crude Oil Transportation & Logistics segment revenues were $96.1 million for the three months ended June 30, 2017, compared to $93.6 million for the three months ended June 30, 2016, which represents an increase of $2.5 million, or 3%, in segment revenues driven by a $5.9 million increase in sales of crude oil primarily due to increased volumes sold during the three months ended June 30, 2017 as a result of more favorable pricing than during the three months ended June 30, 2016, partially offset by a $3.5 million decrease in crude oil transportation services, primarily due to a $3.4 million increase in shipper deficiency payments and a $2.6 million decrease in the incremental barrels delivered during the three months ended June 30, 2017 compared to the three months ended June 30, 2016, partially offset by a $2.6 million increase in committed barrels shipped.

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation & Logistics segment were $44.3 million for the three months ended June 30, 2017 compared to $46.4 million for the three months ended June 30, 2016, which represents a decrease of $2.1 million, or 5%. The overall decrease in operating costs and expenses was primarily driven by the $8.1 million buyout of an operating agreement at the Sterling Terminal during the three months ended June 30, 2016, partially offset by a $5.4 million increase in cost of sales primarily due to increased volumes of crude oil sold during the three months ended June 30, 2016 and a $1.2 million increase in taxes, other than income taxes driven by assets placed in service throughout 2016.

Six Months Ended June 30, 2017 Compared to the Six Months Ended June 30, 2016

Revenues. Crude Oil Transportation & Logistics segment revenues were $181.1 million for the six months ended June 30, 2017, compared to $188.2 million for the six months ended June 30, 2016, which represents a decrease of $7.1 million, or 4%, in segment revenues driven by a $13.7 million decrease in crude oil transportation services, primarily due to a $10.0 million increase in shipper deficiency payments and a $8.1 million decrease in the incremental barrels delivered during the six months ended June 30, 2017 compared to the six months ended June 30, 2016, partially offset by a $4.2 million increase in committed barrels shipped. The decrease in crude oil transportation services was partially offset by a $6.5 million increase in sales of crude oil primarily due to increased volumes of crude oil sold during the six months ended June 30, 2017 as a result of more favorable pricing than during the six months ended June 30, 2016.

Operating costs and expenses. Operating costs and expenses in the Crude Oil Transportation & Logistics segment were $84.7 million for the six months ended June 30, 2017 compared to $87.1 million for the six months ended June 30, 2016, which represents a decrease of $2.5 million, or 3%. The overall decrease in operating costs and expenses was primarily driven by the $8.1 million buyout of an operating agreement at the Sterling Terminal during the six months ended June 30, 2016 and a $1.0 million decrease in cost of transportation services driven by lower throughput volumes during the six months ended June 30, 2017 compared to the six months ended June 30, 2016. These decreases were partially offset by a $5.4 million increase in cost of sales primarily due to increased volumes of crude oil sold during the six months ended June 30, 2017 and a $1.6 million increase in taxes, other than income taxes driven by assets placed in service throughout 2016.

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,	
	2017	2016	2017	2016
	(in thousands)			
Revenues:				
Natural gas transportation services	$30,871	$30,092	$64,001	$60,727
Sales of natural gas, NGLs, and crude oil	539	48	2,190	396
Processing and other revenues	1,700	2,002	3,347	3,687
Total revenues	33,110	32,142	69,538	64,810
Operating costs and expenses:				
Cost of sales	521	373	1,591	1,519
Cost of transportation services	482	842	1,242	3,297
Operations and maintenance	7,910	7,806	14,388	13,686
Depreciation and amortization	4,792	5,479	9,575	11,357
General and administrative	3,560	4,408	7,354	8,196
Taxes, other than income taxes	1,119	1,142	2,494	2,318
Total operating costs and expenses	18,384	20,050	36,644	40,373
Operating income	$14,726	$12,092	$32,894	$24,437

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 14 – Reportable Segments to the accompanying condensed consolidated financial statements.

Three Months Ended June 30, 2017 Compared to the Three Months Ended June 30, 2016

Revenues. Natural Gas Transportation & Logistics segment revenues were $33.1 million for the three months ended June 30, 2017, compared to $32.1 million for the three months ended June 30, 2016, which represents an increase of $1.0 million, or 3%, in segment revenues primarily due to a $0.8 million increase in natural gas transportation services and a $0.5 million increase in natural gas sales, partially offset by a $0.3 million decrease in other revenues. The increase in natural gas transportation services was driven by increased tariff rates at TIGT, partially offset by a change in the fuel recovery structure, beginning May 1, 2016 as a result of the rate case settlement discussed in Note 12 – Regulatory Matters, as well as higher volumes transported at Trailblazer due to the increased expansion capacity resulting from the pipeline integrity management program. The $0.5 million increase in natural gas sales was primarily driven by a noncash mark-to-market loss on natural gas commodity derivative contracts during the three months ended June 30, 2016 and a 38% increase in natural gas prices during the three months ended June 30, 2017 compared to the three months ended June 30, 2016.

Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation & Logistics segment were $18.4 million for the three months ended June 30, 2017, compared to $20.1 million for the three months ended June 30, 2016, which represents a decrease of $1.7 million, or 8%. The overall decrease in operating costs and expenses was primarily due to a $0.8 million decrease in general and administrative costs driven by higher costs associated with compliance activities and shared service allocations during the three months ended June 30, 2016 and a $0.7 million decrease in depreciation and amortization driven by changes in depreciation rates at TIGT as a result of the rate case settlement discussed above.

Six Months Ended June 30, 2017 Compared to the Six Months Ended June 30, 2016

Revenues. Natural Gas Transportation & Logistics segment revenues were $69.5 million for the six months ended June 30, 2017, compared to $64.8 million for the six months ended June 30, 2016, which represents an increase of $4.7 million, or 7%, in segment revenues due to a $3.3 million increase in natural gas transportation services driven by increased tariff rates at TIGT, partially offset by a change in the fuel recovery structure, as a result of the rate case settlement discussed above, as well as increased volumes transported at Trailblazer, and a $1.8 million increase in natural gas sales driven by increased volumes sold and a 38% increase in natural gas prices during the six months ended June 30, 2017 compared to the six months ended June 30, 2016.

Operating costs and expenses. Operating costs and expenses in the Natural Gas Transportation & Logistics segment were $36.6 million for the six months ended June 30, 2017, compared to $40.4 million for the six months ended June 30, 2016, which represents a decrease of $3.7 million, or 9%. The overall decrease in operating costs and expenses was primarily due to a $2.1 million decrease in the cost of transportation services driven by lower costs associated with fuel reimbursements as a result of changes to TIGT's fuel recovery structure and a $1.8 million decrease in depreciation and amortization driven by changes in depreciation rates at TIGT, both as a result of the rate case settlement discussed above.

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,	
	2017	2016	2017	2016
	(in thousands)			
Revenues:				
Sales of natural gas, NGLs, and crude oil	$16,372	$16,634	$29,439	$30,212
Processing and other revenues	16,771	8,087	28,029	15,710
Total revenues	33,143	24,721	57,468	45,922
Operating costs and expenses:				
Cost of sales	13,513	15,649	24,914	28,081
Cost of transportation services	4,480	592	7,374	1,143
Operations and maintenance	3,577	2,848	6,252	5,614
Depreciation and amortization	3,819	3,124	7,032	6,299
General and administrative	1,908	1,607	3,029	3,283
Taxes, other than income taxes	400	424	753	847
Loss (gain) on disposal of assets	184	1,849	(1,264)	1,849
Total operating costs and expenses	27,881	26,093	48,090	47,116
Operating income (loss)	$5,262	$(1,372)	$9,378	$(1,194)

(1) Segment results as presented represent total revenue and operating income, including intersegment activity. For reconciliations to the consolidated financial data, see Note 14 – Reportable Segments to the accompanying condensed consolidated financial statements.

Three Months Ended June 30, 2017 Compared to the Three Months Ended June 30, 2016

Revenues. Processing & Logistics segment revenues were $33.1 million for the three months ended June 30, 2017, compared to $24.7 million for the three months ended June 30, 2016, which represents an $8.4 million, or 34%, increase in segment revenues. The increase in segment revenues was primarily due to a $8.7 million increase in processing and other revenues driven by increased water business services revenue of $8.5 million as a result of increased fresh water transportation and produced water disposal volumes, partially offset by a $0.3 million decrease in sales of natural gas, NGLs, and crude oil. The decrease in sales of natural gas, NGLs, and crude oil was driven by lower volumes of NGLs sold, partially offset by a 16% increase in NGL prices and one month of residue natural gas sales from the Douglas Gathering System acquired on June 5, 2017.

Operating costs and expenses. Operating costs and expenses in the Processing & Logistics segment were $27.9 million for the three months ended June 30, 2017 compared to $26.1 million for the three months ended June 30, 2016, which represents an increase of $1.8 million, or 7%. The increase in operating costs and expenses was primarily due to a $3.9 million increase in cost of transportation services, driven by increased volumes in water business services as discussed above, and a $0.7 million increase in operations and maintenance and a $0.7 million increase in depreciation and amortization, both driven by the acquisition of the Douglas Gathering System. These increased costs were partially offset by a $2.1 million decrease in cost of sales driven by lower NGL sales and a $1.7 million decrease in loss on disposal of assets primarily related to assets destroyed by a fire caused by a lightning strike during the three months ended June 30, 2016.

Six Months Ended June 30, 2017 Compared to the Six Months Ended June 30, 2016

Revenues. Processing & Logistics segment revenues were $57.5 million for the six months ended June 30, 2017, compared to $45.9 million for the six months ended June 30, 2016, which represents a $11.5 million, or 25%, increase in segment revenues. The increase in segment revenues was primarily due to a $12.3 million increase in processing and other revenues driven by increased water business services revenue of $13.3 million as a result of increased fresh water transportation and produced water disposal volumes. The increase in processing and other revenues was partially offset by a $0.8 million decrease in sales of natural gas, NGLs, and crude oil. The decrease in sales of natural gas, NGLs, and crude oil was driven by lower volumes of NGLs sold, partially offset by a 43% increase in NGL prices and one month of residue natural gas sales from the Douglas Gathering System.

Operating costs and expenses. Operating costs and expenses in the Processing & Logistics segment were $48.1 million for the six months ended June 30, 2017 compared to $47.1 million for the six months ended June 30, 2016, which represents an increase of $1.0 million, or 2%. The increase in operating costs and expenses was primarily due to a $6.2 million increase in cost of transportation services driven by increased fresh water transportation and produced water disposal volumes and a $0.7 million increase in depreciation and amortization driven by the acquisition of the Douglas Gathering System as discussed above. These increases were partially offset by a $3.2 million decrease in cost of sales driven by decreased NGL sales and a $3.1 million decrease in loss (gain) on disposal of assets primarily driven by a gain on disposal of assets from insurance proceeds received during the six months ended June 30, 2017 related to assets destroyed by a fire caused by a lightning strike during the six months ended June 30, 2016.

Liquidity and Capital Resources Overview

Our primary sources of liquidity for the three months ended June 30, 2017 were proceeds from the issuance of long-term debt, 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. For additional information regarding our revolving credit facility and senior unsecured notes, see Note 9 – Long-term Debt. For additional information regarding our equity transactions, see Note 10 – Partnership Equity and Distributions.

Our total liquidity as of June 30, 2017 and December 31, 2016 was as follows:

	June 30, 2017	December 31, 2016
	(in thousands)	
Cash on hand	$240	$1,873
Total capacity under the revolving credit facility	1,750,000	1,750,000
Less: Outstanding borrowings under the revolving credit facility	(1,348,000)	(1,015,000)
Less: Letters of credit issued under the revolving credit facility	(60)	—
Available capacity under the revolving credit facility	401,940	735,000
Total liquidity	$402,180	$736,873

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, accounts payable and deferred revenue. We manage our working capital needs through borrowings and repayments of borrowings under our revolving credit facility. 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. Factors impacting deferred revenue include the volume of barrels transported, the amount of deficiency payments received, and the volume of prior deficiencies utilized during the period.

As of June 30, 2017, we had a working capital deficit of $80.5 million compared to a working capital deficit of $38.1 million at December 31, 2016, which represents an increase in the working capital deficit of $42.4 million. The overall increase in the working capital deficit was primarily attributable to changes in the following components:

- an increase in deferred revenue of $24.8 million primarily from deficiency payments collected by Pony Express;
- a decrease in derivative assets at fair value of $10.7 million as we exercised the remainder of the call option granted by TD;

- an increase in accrued liabilities of $1.9 million primarily due to an increase in accrued interest driven by increased borrowings under the revolving credit facility and the issuance of the 2024 Notes; and
- a decrease in inventory of $1.9 million primarily due to sales of crude oil during the six months ended June 30, 2017.

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,	
	2017	2016
	(in thousands)	
Net cash provided by (used in):		
Operating activities	$241,851	$205,507
Investing activities	$(727,034)	$(527,704)
Financing activities	$483,550	$322,529

Six Months Ended June 30, 2017 Compared to the Six Months Ended June 30, 2016

Operating Activities. Cash flows provided by operating activities were $241.9 million and $205.5 million for the six months ended June 30, 2017 and 2016, respectively. The increase in net cash flows provided by operating activities of $36.3 million was primarily driven by a $38.7 million increase in distributions received from Rockies Express.

Investing Activities. Cash flows used in investing activities were $727.0 million for the six months ended June 30, 2017. Investing cash outflows for the six months ended June 30, 2017 were primarily driven by:

- cash outflows of $400.0 million for the acquisition of an additional 24.99% membership interest in Rockies Express on March 31, 2017;
- cash outflows of $140.0 million for the acquisition of Terminals and NatGas on January 1, 2017;
- cash outflows of $128.5 million for the acquisition of the Douglas Gathering System on June 5, 2017;
- capital expenditures of $54.0 million, primarily due to spending on an additional freshwater connection at Water Solutions and remediation digs on the Pony Express System as discussed in Note 13 – Legal and Environmental Matters; and
- contributions to Rockies Express in the amount of $17.8 million.

These cash outflows were partially offset by $27.3 million of distributions from Rockies Express in excess of cumulative earnings recognized.

Cash flows used in investing activities were $527.7 million for the six months ended June 30, 2016. Investing cash outflows for the six months ended June 30, 2016 were primarily driven by:

- cash outflows of $436.0 million for the acquisition of a 25% membership interest in Rockies Express on May 6, 2016;
- cash outflows of $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 $34.9 million, primarily due to post in-service spending on Pony Express System projects and costs associated with construction of the Buckingham Terminal.

Financing Activities. Cash flows provided by financing activities were $483.6 million for the six months ended June 30, 2017. Financing cash inflows for the six months ended June 30, 2017 were primarily driven by:

- proceeds from the issuance of $350.0 million in aggregate principal amount of 5.50% Senior Notes due 2024;
- net borrowings under the revolving credit facility of $333.0 million; and
- net cash proceeds of $112.8 million from the issuance of 2,341,061 common units under our Equity Distribution Agreements.

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

- distributions to unitholders of $179.5 million;
- $72.4 million for the exercise of the remainder of the call option granted by TD covering 1,703,094 common units; and
- $35.3 million for the 736,262 common units repurchased from TD.

Cash flows provided by financing activities were $322.5 million for the six months ended June 30, 2016. 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;
- net cash proceeds of $261.8 million from the issuance of 6,081,138 common units under the Equity Distribution Agreements; and
- net cash proceeds of $90.0 million from the issuance of 2,416,987 common units representing limited partnership interests in a private placement transaction.

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.

Distributions

We do not have a legal obligation to pay distributions except as provided in our partnership agreement. A distribution of $0.9250 per unit, or $105.2 million in the aggregate, for the three months ended June 30, 2017 was announced on July 5, 2017 and will be paid on August 14, 2017 to unitholders of record on July 28, 2017. As of August 2, 2017, we had a total of 73,992,024 common and general partner units outstanding, which equates to an aggregate minimum quarterly distribution of approximately $21.3 million per quarter and approximately $85.1 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 we expect will 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 $150 million for expansion capital projects and approximately $15 million, net of anticipated reimbursements, for maintenance capital expenditures in 2017.

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,	
	2017	2016
	(in thousands)	
Maintenance capital expenditures	$4,057	$4,257
Expansion capital expenditures	44,227	19,639
Total capital expenditures incurred	$48,284	$23,896

Capital expenditures incurred represent capital expenditures paid and accrued during the period. Capital expenditures are presented net of noncontrolling interest, and contributions and reimbursements received. The decrease in maintenance capital expenditures to $4.1 million for the six months ended June 30, 2017 from $4.3 million for the six months ended June 30, 2016 is primarily driven by contributions from TD to TEP in order to indemnify TEP for certain out of pocket costs related to repairing or remediating the Trailblazer Pipeline, as discussed further in Note 13 – Legal and Environmental Matters. 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 increase in expansion capital expenditures to $44.2 million for the six months ended June 30, 2017 is primarily driven by increased expansion capital expenditures in the Processing & Logistics and Crude Oil Transportation & Logistics segments. Expansion capital expenditures for the six months ended June 30, 2017 consisted primarily of spending on an additional freshwater connection at Water Solutions and remediation digs on the Pony Express System, as discussed in Note 13 – Legal and Environmental Matters. Expansion capital expenditures of $19.6 million for the six months ended June 30, 2016 consisted primarily of post in-service spending on Pony Express System projects and costs associated with construction of the Buckingham Terminal.

In addition, we invested cash in unconsolidated affiliates of $17.8 million and $14.5 million during the six months ended June 30, 2017 and 2016, respectively, to fund our share of capital projects. During the six months ended June 30, 2017, we invested $7 million in a new unconsolidated affiliate, BNN Colorado Water, LLC ("BNN Colorado"). In connection with the investment in BNN Colorado, we made a commitment to fund capital expenditures estimated at $10.5 million, primarily during the remainder of 2017.

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 2016 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 2016 Form 10-K for the year ended December 31, 2016 and have not changed.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Prior to our acquisition of the Douglas Gathering System on June 5, 2017, approximately 99% 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. With our acquisition of the Douglas Gathering System, the largest existing firm fee contract was terminated because the counterparty to this contract, DCP Douglas, LLC, became our indirect wholly-owned subsidiary. In addition, we acquired a number of commodity sensitive gathering and processing contracts such as percent of proceeds or keep whole processing contracts in the acquisition. The integration of the Douglas Gathering System is ongoing and we are continuing to evaluate the ultimate impact from the acquisition on the percentage of our reserved processing capacity subject to firm or volumetric fee contracts.

Our Processing & Logistics segment comprised approximately 6% and 3% of our Adjusted EBITDA for the six months ended June 30, 2017 and 2016, respectively. 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. Starting in the second half of 2014, the prices of crude oil, natural gas, and NGLs became extremely volatile and declined significantly. Downward pressure and volatility of commodity prices continued in 2015 before recovering somewhat in 2016 and 2017. These declines directly and indirectly resulted in lower realizations and processing volumes on our percent of proceeds and keep whole processing contracts.

Historically, we have had a limited amount of direct commodity price exposure related to natural gas collected for electrical compression costs and lost and unaccounted for gas on the TIGT System. Accordingly, we have historically entered into derivative contracts with third parties for a substantial majority of the natural gas we expected to collect for the purpose of hedging our commodity price exposures. In 2016, we also entered into long natural gas swaps covering a portion of the natural gas that TMID expects to purchase in 2017. In addition, 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 and Terminals. During 2016, we began entering into derivative contracts for the sale of crude oil inventory.

We measure the risk of price changes in our crude oil and 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 primarily 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.

The following table summarizes our commodity derivatives and the change in fair value that would be expected from a 10% price increase or decrease as of June 30, 2017, assuming a parallel shift in the forward curve through the end of 2017:

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
	(in thousands)		
Crude oil derivative contracts [1]	$207	$ (139)	$ 139
Natural gas derivative contracts [2]	$13	$ 58	$ (58)

(1) Represents the sale of 30,000 barrels of crude oil by our Crude Oil Transportation & Logistics segment which will settle throughout 2017.

(2) Represents long natural gas swaps outstanding with a notional volume of approximately 0.2 Bcf covering a portion of the natural gas that is expected to be purchased by our Processing & Logistics segment throughout 2017.

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 implemented 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 continue to qualify for an exemption to the clearing and exchange-execution requirements, we will still be subject to record keeping and reporting requirements.

Interest Rate Risk

As of June 30, 2017, we have issued $750 million of 5.50% senior notes due 2024. In addition, we have a $1.75 billion revolving credit facility with borrowings of approximately $1.35 billion as of June 30, 2017. 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. The applicable margin ranges from 0.75% to 1.75% for the three months ended June 30, 2017 and 0.50% to 2.50% for periods after June 30, 2017, 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 $0.6 million based on our debt obligations as of June 30, 2017.
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.

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 a majority of our revenues derived from customers who have BB+ or Ba1 and better credit ratings or are part of corporate families with such credit ratings as of June 30, 2017.

We also have indirect credit risk exposure with respect to our investment in Rockies Express. See Item 1A.—Risk Factors in our 2016 Form 10-K 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, 2017 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 13 – 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 herein by reference.

Item 1A. Risk Factors

Item 1A of our 2016 Form 10-K for the year ended December 31, 2016 sets 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, 2017. There have been no material changes to the risk factors contained in our 2016 Form 10-K for the year ended December 31, 2016.

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*	Second Amended and Restated Credit Agreement, dated June 2, 2017, by and among the Partnership, Wells Fargo Bank, National Association, as administrative agent, and a syndicate of lenders named therein.
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 2, 2017	By:	/s/ Gary J. Brauchle	
			Name:	Gary J. Brauchle
			Title:	Executive Vice President and Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)

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